NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

May 5, 2009

VIA ELECTRONIC FILING

Ms. Erica Hamilton, Commission Secretary
British Columbia Utilities Commission
Box 250, 900 Howe Street
Sixth Floor
Vancouver, B.C.
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Re: *North American Electric Reliability Corporation*

Dear Ms. Hamilton:

The North American Electric Reliability Corporation ("NERC") hereby submits this notice of filing of interpretations of requirements in two NERC Reliability Standards that are contained in **Exhibits A-1 and B-1** to this petition:

- TPL-002-0 — System Performance Following Loss of a Single Bulk Electric System Element (Category B), Requirements R1.3.2 and R1.3.12
- TPL-003-0 — System Performance Following Loss of a Two or More Bulk Electric System Elements (Category C), Requirements R1.3.2 and R1.3.12

The formal interpretations have been approved by the NERC Board of Trustees. .

NERC's notice consists the following:

- This transmittal letter;
- A table of contents for the entire notice;
- A narrative description explaining how the formal interpretations meet the reliability goal of the standards involved;
- Formal interpretations submitted for approval (**Exhibits A-1 and B-1**);
- Affected Reliability Standards that include the appended interpretations **(Exhibits A-2 and B-2);** and

- The complete development record of the formal interpretations (**Exhibits A-3 and B-3)**.

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Rebecca J. Michael

Rebecca J. Michael

Attorney for North American Electric Reliability Corporation

BEFORE THE
BRITISH COLUMBIA UTILITIES COMMISSION
OF THE PROVINCE OF BRITISH COLUMBIA

NORTH AMERICAN ELECTRIC)
RELIABILITY CORPORATION)

NOTICE OF FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION OF FORMAL INTERPRETATIONS TO RELIABILITY STANDARDS

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Exhibit B-3 – Record of Development of Formal Interpretations for Reliability Standard TPL-002-0 — System Performance Following Loss of a Single Bulk Electric System Element (Category B) and TPL-003-0 — System Performance Following Loss of a Two or More Bulk Electric System Elements (Category C), Requirements R1.3.2 and R1.3.12 – Midwest ISO

I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC") hereby submits notice of interpretations to requirements of two NERC Reliability Standards:

- TPL-002-0 — System Performance Following Loss of a One Bulk Electric System Element (Category B), Requirements R1.3.2 and R1.3.12

- TPL-003-0 — System Performance Following Loss of a Two or More Bulk Electric System Elements (Category C), Requirements R1.3.2 and R1.3.12

No modifications to the language contained in these specific requirements are being proposed.

The NERC Board of Trustees approved the formal interpretation to: TPL-002-0 — System Performance Following Loss of a One Bulk Electric System Element (Category B), Requirements R1.3.2 and R1.3.12 and TPL-003-0 — System Performance Following Loss of a Two or More Bulk Electric System Elements (Category C), Requirements R1.3.2 and R1.3.12 on July 30, 2008. Exhibits A-1 and B-1 to this filing set forth the formal interpretations. Exhibits A-2 and B-2 contain the affected Reliability Standards containing the appended interpretations. Exhibits A-3 and B-3 contain the complete development record of the formal interpretations to the Reliability Standard requirements as requested by Ameren Corporation (Ameren) and the Midwest Independent Transmission System Operator (MISO).

NERC filed these formal interpretations with the Federal Energy Regulatory Commission ("FERC") and is filing them with the other applicable governmental authorities in Canada.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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III. BACKGROUND

a. Reliability Standards Development Procedure

All persons who are directly or materially affected by the reliability of the North American bulk power system are permitted to request an interpretation of the Reliability Standard, as discussed in NERC's *Reliability Standards Development Procedure.* When requested, NERC will assemble a team with the relevant expertise to address the interpretation request and, within 45 days, present a formal interpretation for industry ballot. If approved by the ballot pool and the NERC Board of Trustees, the interpretation is appended to the Reliability Standard and filed for approval by the applicable regulatory authorities to be made effective when approved. When the affected Reliability Standard is next revised using the Reliability Standards Development Process, the interpretation will then be incorporated into the Reliability Standard.

The formal interpretations set out in Exhibits A-1 and B-1 have been developed and approved by industry stakeholders using NERC's *Reliability Standards Development*

Procedure; they have been approved by the NERC Board of Trustees as outlined in the Introduction section above.

IV. TPL-002-0 — System Performance Following Loss of a One Bulk Electric System Element (Category B) and TPL-003-0 — System Performance Following Loss of a Two or More Bulk Electric System Elements (Category C), Requirements R1.3.2 and R1.3.12

On July 25, 2007, NERC received a request for interpretation from Ameren to clarify two different sub-requirements (Requirements R1.3.2 and R1.3.12) common to TPL-002-0 — System Performance Following Loss of a One Bulk Electric System Element (Category B) and TPL-003-0 — System Performance Following Loss of a Two or More Bulk Electric System Elements (Category C) pertaining to the simulation testing to assess system performance for Category B and Category C contingencies as defined in Table 1 of the standards. On August 9, 2007, MISO submitted a request for interpretation of these same requirements. Because both entities' requests for interpretation pertained to the same requirements and issues, NERC combined the response to the Ameren and MISO requests for Requirement R1.3.2, as well as that for Requirement R1.3.12. NERC addresses these issues in Sections IV (a) and (b) below. The responses to the requests for interpretation were balloted on an entity basis,[1] and the summary of these proceedings is presented in Section IV(c) below.

Sections IV(a) and (b) explain the need for, and development of, the formal interpretation of Requirements R1.3.2 and R1.3.12, respectively, of TPL-002-0 — System Performance Following Loss of a One Bulk Electric System Element (Category B) and TPL-003-0 — System Performance Following Loss of a Two or More Bulk Electric System Elements (Category C). In these sections, NERC demonstrates that the

[1] NERC conducted two ballots, one for Ameren and one for MISO. Each ballot included the response to the interpretation request for Requirements R1.3.2 and R1.3.12 for TPL-002 and TPL-003.

formal interpretation is consistent with the stated reliability goal of the Reliability Standards and the requirements therein.

The complete development records for the formal interpretations to TPL-002-0 and TPL-003-0 are set forth in Exhibits A-3 and B-3. Exhibit A-3 provides the record of development for the Ameren request and Exhibit B-3 provides the record with respect to the MISO request. Each record includes the request for interpretation, the response to the request for interpretation, the ballot pool and the final ballot results by registered ballot body members, stakeholder comments received during the balloting and how those comments were considered.

The purpose of TPL-002-0 — System Performance Following Loss of a One Bulk Electric System Element (Category B) and TPL-003-0 — System Performance Following Loss of a Two or More Bulk Electric System Elements (Category C) is identical: "[s]ystem simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs." Requirement R1 requires the Planning Authority and Transmission Planner to perform a valid assessment to demonstrate the system is planned to meet customer demand and projected firm transmission services under contingencies outlined in Category B of Table 1 in TPL-002-0 and Category C for TPL-003-0. Requirement R1 goes on to state that to be valid, the assessment shall be supported by studies that may include simulation testing (R1.3) to cover critical system conditions (R1.3.2) and include planned maintenance outages (R1.3.12) at demand levels when outages are performed.

TPL-002-0 and TPL-003-0, Requirements R1.3.2 and R1.3.12 serve as the basis for the interpretation requests:

TPL-002-0 — System Performance Following Loss of a Single BES Element

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R.1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0 — System Performance Following Loss of a Two or More BES Elements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R.1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

a. Justification of Formal Interpretation for Requirement R1.3.2 of TPL-002-0 — System Performance Following Loss of a Single Bulk Electric System Element (Category B) and TPL-003-0 — System Performance Following Loss of a Two or More Bulk Electric System Elements (Category C)

In its request for interpretation of Requirement R1.3.2, Ameren specifically asks two questions:

1. How should the phrase "critical system conditions" be interpreted?
2. Does compliance with R1.3.2 require multiple contingent generation unit outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be operated in accordance with the contingency definitions included in Table 1 of the TPL standards?

Ameren then offers two possible interpretations that question whether multiple contingent generation outages that might be evidenced in a resource adequacy planning evaluation are intended to be included in addition to the transmission contingency conditions found in Table 1. Ameren requests clarity on this requirement because:

- Interpretation is necessary to establish appropriate cost allocation of proposed system expansion in the MISO footprint;

- If multiple contingent generation outages associated with a resource adequacy evaluation are to be included:
  - it will be difficult to determine which contingent generation outages are related to critical conditions and which are part of contingency definitions making inconsistent the application of contingency definitions in Table 1.
  - compliance assessment will be more difficult as the number of contingent generator unit outages is at the judgment of the Transmission Planner or Transmission coordinator;
  - there is a de facto transfer capability requirement created; and,
  - the hurdles for connection of new generation will dramatically increase.

In its request for interpretation, the MISO requested guidance on the following general topics:

1. The application of the TPL contingency requirements of Table 1 to dispatch patterns considered appropriate by the entity responsible for compliance is not a misapplication of the standard as it within the bounds of discretion that the standard permits of the Transmission Planner and the Planning Authority as entities responsible for compliance; and,
2. The application of a standard in accordance with an existing interpretation based on the history and development of the standards is appropriate, notwithstanding future interpretations or revisions of the standard.

Specifically, MISO asks for clarity with respect to Requirement R1.3.2:

1. Do the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies as specified in Table 1 of the TPL standards?
2. If in the judgment of the entity responsible for compliance, a variety of possible dispatch patterns should be included in the planning analyses including a

probabilistic based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch patterns?

MISO states that interpretation is necessary for the following reasons:

- Necessary transmission expansions may not be pursued as regulatory authorities may not permit recovery of costs if the standards are construed to prescribe the precise system conditions to be considered without permitting discretion in assumptions.
- The application of the standards must permit discretion by the Transmission Planners and Planning Authorities to plan their systems to perform reliably based on their experience with and historical performance of the systems, including the assumptions used for developing the planning models. The standards should not be interpreted to prescribe the generation patterns, including the number of generators off-line that is prudent to plan for.
- The reinterpretation of how the standard is applied after many years of use would create great uncertainty in the ability of the Transmission Owner to recover costs for upgrades, and cause reluctance to expand their systems.

NERC assigned its Planning Committee the responsibility to develop the response to the Ameren and MISO interpretation requests. The Planning Committee provided its initial response to the request for interpretation for R1.3.2 that was presented for pre-ballot review on November 5, 2007 and then initial ballot on December 4, 2007. The original text of the interpretation response for Requirement R1.3.2 of TPL-002-0 and TPL-003-0 states:

> TPL-002 and TPL-003 do not specify the process for selection of the credible critical generation dispatch modeling of critical system conditions. The selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority/Transmission Planner.

Although most balloters agreed with the interpretation by virtue of the approval percentage exceeding that necessary for passage, several stakeholders indicated that the interpretation did not adequately address the questions that were asked. In response to these stakeholder comments, the Planning Committee concurred with the commenters, decided to withdraw its original response, and revised its interpretation. The revised interpretation was presented for pre-ballot review for a second initial ballot on March 24, 2008, and states:

> The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and TPL-003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)
>
> - Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."
>
> Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.
>
> Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].
>
> The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

In responding to the two requests for interpretation, NERC and its Planning Committee were faced with a host of questions that, in order to respond to completely, would require re-writing of the requirements and establishment of additional terms for inclusion in NERC's Glossary of Terms. In both cases, the interpretation process, as implemented, does not permit these activities. Rather, the interpretation process permits a clarification of the requirement but not an expansion or re-definition of it. Accordingly, several key issues from the interpretation requests could not be directly answered by the Planning Committee serving as the drafting team. Of paramount importance is the term "critical system conditions" that is currently not defined in NERC's Glossary of Terms and not explained further in TPL-002-0 or TPL-003-0. While Ameren sought further specificity regarding the term, the drafting team could not provide additional specificity without violating the fundamental basis of the interpretation process. In lieu of defining the term "critical system conditions," the interpretation response provides the process for obtaining how "critical system conditions" are determined, using the Planning

Coordinator in a supervisory role over the Transmission Planners in directing the coordination of the planning process.

In support of this response, the Planning Committee cited the descriptions of the Planning Coordinator and Transmission Planner in the Functional Model, Version 3 as a guide used to support and articulate its position. NERC understands that the TPL-002-0 and TPL-003-0 reliability standards include the "Planning Authority" as an applicable entity and that the use of the Planning Coordinator may seem inconsistent in the interpretation response. However, NERC has explained that the intent of the two functions is the same, making it acceptable to utilize this approach in the interpretation. This applies equally here.

Finally, the drafting team added specificity to the original interpretation by adding that the Regional Entity, as the Compliance Monitor, would ultimately determine what constitutes a "valid assessment" through its compliance enforcement responsibilities.

During the second initial ballot of the interpretation response to Requirement R1.3.2, there were several themes in the comments offered by the balloters, as follows:

- The response to interpretation does not adequately answer the questions posed regarding contingent outages or critical system conditions. As stated in the discussion, the team agreed in principle but cited that the questions venture beyond interpreting the current version of the standard and would require revising the standards to adequately address. Further, as the term "critical system conditions" is undefined, the team was not permitted to directly answer the question. However, the team did articulate a process for obtaining the specificity desired by the requesters and the Planning Committee has the authority to specify "critical system conditions."
- Commenters questioned the selection of the Planning Coordinator in a supervisory role overseeing the coordination of the planning process in the footprint, including the specification of methodologies to be use by the Transmission Planners in its footprint. Some commenters felt the Transmission Planner and Planning Authority had an equal responsibility in this regard. The Planning Committee offered that its interpretation was valid because both entities

are included in the applicability of the standard and thus, their interpretation was permissible. Further, they argued that, if Transmission Planners were permitted to adopt its own methodologies, the Planning Coordinator's and Transmission Planner's assessments would be invalid due to the lack of coordination.

- Commenters cited confusion over the Regional Entities' role in determining a valid assessment. The Planning Committee responded that this determination is part of the compliance enforcement process and that which a compliance audit requires. The Regional Entity must determine whether a valid assessment was performed as required by the TPL standards.

NERC believes that the interpretation as presented directly supports the reliability purpose of the standard, that is, to periodically perform a valid assessment. This interpretation helps to clarify assignments in responsibility regarding the determination and validation of critical system conditions that are fundamental to the requirements in the TPL-002-0 and TPL-003-0 Reliability Standards. Further, NERC implemented its process for interpretations by responding to the request in a fashion that did not re-define or expand the aforementioned requirements.

NERC notes that the entire set of Transmission Planning Reliability Standards is currently under review and modification as an integral part of Project 2006-02 – Assess Transmission Future Needs, a key project in the current version of NERC's three-year *Reliability Standards Development Plan: 2008-2010* currently on record.

b. Justification of Formal Interpretation for Requirement R1.3.12 of TPL-002-0 — System Performance Following Loss of a Single Bulk Electric System Element (Category B) and TPL-003-0 — System Performance Following Loss of a Two or More Bulk Electric System Elements (Category C)

In its request for interpretation of Requirement R1.3.12, Ameren specifically asks two questions:

1. How should the inclusion of planned outages be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C?
2. Does compliance with R1.3.12 require that the system be planned to operate during those conditions associated with planned outages consistent with the

> performance requirements described in Table 1 **plus** any unidentified planned outage?

Ameren then offers two possible interpretations that question whether it is permissible to reposition the system in response to a planned outage before performing the Category B or C assessments. Ameren notes that the NERC planning standard (I.A.S2) from which the TPL-002-0 and TPL-003-0 were originally translated stated that "systems must be able of meeting Category B requirements while **accommodating** the planned…outage of any bulk electric equipment…at those demands levels for which planned…outages are performed." Ameren requests clarity on this requirement because:

- Interpretation is necessary to establish appropriate cost allocation of proposed system expansion in the MISO footprint;
- If the system were not able to be repositioned in response to a planned outage prior to a Category B or C assessment,
  - the system should be planned such that maintenance outages can be scheduled without the need to consider mitigation plans, alternate generation dispatch, or other outage coordination efforts that may facilitate maintenance outages.
  - there will be confusion regarding appropriate contingency levels and mitigation options to be included under conditions when planned outages are typically planned.
  - the hurdles for connection of new generation will dramatically increase due to the increase in contingency levels used in connection studies of off-peak conditions.

In its request for interpretation, MISO asks four questions regarding Requirement R1.3.12:

1. Does the term "planned outages" mean only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?
2. If it is intended to include a not yet scheduled but potential planned outage that could occur in the planning horizon, is the following a proper interpretation of this provision? The system is adequately planned and in accordance with the standards if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, redispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base case condition?
3. If it is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is the interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase 1 development of this standard?
4. If NERC provides a new interpretation of a standard, or an interpretation that is different than a prior clarification by NERC of a standard, or if NERC revises a standard, would the previous application of the standard according to the clarification, interpretation, or version of a standard i<u>n effect at the time it was applied</u> be considered a proper application of the standard? Is the more recent interpretation deemed to be retroactive, invalidating previous planning studies?

MISO did not specify additional impacts to reliability to those offered in the discussion in Section IV(a).

NERC assigned its Planning Committee the responsibility to develop the response to the Ameren and MISO interpretation requests for R1.3.12. The Planning Committee provided its initial response to the request for interpretation that was presented for pre-ballot review on November 5, 2007 and then initial ballot on December 4, 2007. The original text of the interpretation response for Requirement R1.3.12 of TPL-002-0 and TPL-003-0 states:

> TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed are within the discretion of the Planning Authority/Transmission Planner.

Although most balloters agreed with the interpretation by virtue of the approval percentage exceeding that necessary for passage, several stakeholders indicated that the interpretation did not adequately address the questions that were asked. In response to these stakeholder comments, the Planning Committee concurred with the commenters, decided to withdraw its original response, and revised its interpretation. The revised interpretation clearly states that planned outages are not contingencies, and it is appropriate that studies that include planned outages at the demand levels contemplated for such outages also include any necessary system adjustments needed to accommodate such outages prior to applying Category B and C contingencies per Table 1 in the TPL-002-0 and TPL-003-0 Reliability Standards. The revised interpretation for R1.3.12 was presented for pre-ballot review for a second initial ballot on March 24, 2008, and states:

> This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

NERC believes that the interpretation as presented directly supports the reliability purpose of the standard, that is, to periodically perform a valid assessment by providing useful guidance on the issue of planned outages. This interpretation provides clarity that planned outages do not constitute contingencies as defined in NERC's Glossary of Terms and sets forth the structure for how they should be considered in the development of the models against which Category B and C contingencies are then applied. Further, NERC implemented its process for interpretations by responding to the request in a fashion that did not re-define or expand the aforementioned requirements.

c. Summary of the Reliability Standard Development Proceedings

On July 25, 2007, NERC received a request for interpretation from Ameren to clarify two different sub-requirements common to TPL-002-0 and TPL-003-0 pertaining to the simulation testing to assess system performance for Category B and Category C contingencies as defined in Table 1 of the standards. On August 9, 2007, MISO submitted a request for interpretation of these same requirements. For purposes of effectiveness, as these requests are similar, NERC requested its Planning Committee to address both requests with a single response. However, the response was balloted as individual events for Ameren and MISO.

In accordance with its *Reliability Standard Development Procedure*, NERC presented the response to these interpretations in a pre-ballot review window that opened on November 5, 2007. NERC then conducted individual initial ballots for the Ameren and MISO requests from December 4, 2007 through December 13, 2007 and achieved a quorum of 86.70 percent and 86.10 percent, respectively, with an 88.10 and 87.50 percent approval level.[2] However, upon review of the balloters' comments as described in Sections IV(a) and (b), the Planning Committee determined that it should withdraw the responses to interpretation from the ballot process and more specifically address the concerns raised.

[2] NERC's *Reliability Standards Development Procedure* requires a minimum quorum of 75% of the ballot pool participants to constitute a valid ballot with at least two-thirds affirmative weighted segment vote needed for passage.

After the Planning Committee revised its responses to the interpretation, NERC presented the response for a pre-ballot review window that began on March 24, 2008. NERC then conducted a second set of initial ballots from April 25, 2008 through May 7, 2008 for the Ameren and MISO requests. The ballots achieved a final weighted segment approval of 80.73 percent and 79.89 percent, respectively, with 82.61 percent and 83.01 percent of the ballot pools casting a vote. The ballots also included negative ballots with comments, initiating the need for recirculation ballots.

NERC conducted individual recirculation ballots from June 27, 2008 through July 7, 2008 for the revised Ameren and MISO interpretation responses and achieved a final weighted segment approval of 79.13 percent and 78.31 percent, respectively, with 83.57 percent and 83.98 percent of the ballot pools casting a vote.

The NERC Board of Trustees approved the interpretations at its July 30, 2008 meeting.

Respectfully submitted,

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Exhibit A-1

Formal interpretation submitted for approval

TPL-002-0 — System Performance Following Loss of a One Bulk Electric System Element (Category B), Requirements R1.3.2 and R1.3.12

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO. These requirements state:

> TPL-002-0:
>
> [To be valid, the Planning Authority and Transmission Planner assessments shall:]
>
> **R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
>
> **R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
>
> **R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

> From TPL-003-0:
>
> [To be valid, the Planning Authority and Transmission Planner assessments shall:]
>
> **R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
>
> **R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
>
> **R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Exhibit A-2

Affected Reliability Standard that includes the appended interpretation

TPL-002-0a — System Performance Following Loss of a One Bulk Electric System Element (Category B), Requirements R1.3.2 and R1.3.12

A. Introduction

1. **Title: System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. **Number:** TPL-002-0a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories,, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 and TPL-002-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating[a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No[b] No[b] No[b] No[b]	No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Exhibit A-3

The complete development record of the formal interpretation - Ameren

TPL-002-0 — System Performance Following Loss of a One Bulk Electric System Element (Category B), Requirements R1.3.2 and R1.3.12

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Interpretation of TPL-002-0 Requirements R1.3.2 and Requirement R1.3.12 and the identical requirements (Requirements R1.3.2 and Requirement R1.3.12) in TPL-003-0 for Ameren

Request for Interpretation of TPL-002 and TPL-003 Requirement R1.3.2 received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

R1.3.2	Cover critical system conditions and study years as deemed appropriate by the responsible entity.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002 and TPL-003 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions. The selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority/Transmission Planner.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

R1.3.12	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed are within the discretion of the Planning Authority/Transmission Planner.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Maureen E. Long
Standards Process Manager

November 5, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement:
Three Pre-ballot Windows and Ballot Pools for Interpretations
Open November 5, 2007

The Standards Committee (SC) announces the following standards actions:

Pre-ballot Window and Ballot Pool for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren Both Open November 5, 2007

Ameren submitted a Request for an Interpretation of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements.

The request asked if TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 require multiple contingent generating unit outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be operated in accordance with the contingency definitions included in Table 1. The request also asked if TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 require that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

The Interpretation clarifies that TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions and clarifies that the selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority and the Transmission Planner. The interpretation also states that TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is within the discretion of the Planning Authority and the Transmission Planner.

A new ballot pool to vote on this interpretation has been formed and will remain open up until 8 a.m. (EST) Tuesday, December 4, 2007. During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." The list server for this ballot pool is: bp_Interpret_TPL_Ameren_in@ner.com

The initial ballot for this interpretation will begin at 8 a.m. (EST) on Tuesday, December 4, 2007.

Pre-ballot Window and Ballot Pool for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO Both Open November 5, 2007

MISO submitted a Request for an Interpretation of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements.

The request asked if TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asked if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios.

The request also asked if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

The Interpretation clarifies that TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions and clarifies that the selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority and the Transmission Planner. The interpretation also states that TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is within the discretion of the Planning Authority and the Transmission Planner.

A new ballot pool to vote on this interpretation has been formed and will remain open up until 8 a.m. (EST) Tuesday, December 4, 2007. During the pre-ballot window, members of the ballot pool may communicate with one another by using their “ballot pool list server.” The list server for this ballot pool is: bp_Interpret_TPL_MISO_in@nerc.com

The initial ballot for this interpretation will begin at 8 a.m. (EST) on Tuesday, December 4, 2007.

Pre-ballot Window and Ballot Pool for Interpretation of VAR-001-0 Requirement R4 for Dynegy Both Open November 5, 2007

Dynegy submitted a Request for an Interpretation of VAR-001-1 Requirement R4.

The request asked if the Transmission Operator is implicitly required to have a technical basis for specifying the voltage or reactive power schedule, asked if the voltage or reactive power schedule must be reasonable and practical for the Generator Operator to maintain, and asked what measure should be used to determine if the Transmission Operator has issued a technically based, reasonable and practical voltage or reactive power schedule.

The Interpretation clarifies that VAR-001-1 is only comprised of stated requirements and associated measures and compliance elements. Interpreting an 'implicit' requirement would effectively be adding a new requirement to the standard and needs to be achieved with a Standard Authorization Request (SAR) to modify the standard rather than through an Interpretation. There are no requirements in VAR-001-1 to issue a "technically based, reasonable and practical to maintain voltage or reactive power schedule and associated tolerance band."

A new ballot pool to vote on this interpretation has been formed and will remain open up until 8 a.m. (EST) Tuesday, December 4, 2007. During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." The list server for this ballot pool is: bp_Interpret_VAR_Dynegy_in@nerc.com

The initial ballot for this interpretation will begin at 8 a.m. (EST) on Tuesday, December 4, 2007.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
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July 25, 2007

Maureen E. Long
Standards Process Manager
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Ameren

RE: **Request for Interpretation of NERC Standards TPL-002-0 and TPL-003-0**

Dear Ms. Long:

In accordance with the NERC Reliability Standards Development Procedure, I am requesting a formal interpretation of two sub-requirements which are common to NERC standards TPL-002-0 and TPL-003-0. These sub-requirements are included in R1.3 of both standards and pertain to the simulation testing to assess system performance for Category B and Category C contingencies as defined in Table 1 of the standards. The specific sub-requirements for which clarification is requested are:

> R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
>
> R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.3.2
Questions requiring interpretation:

How should the phrase "critical system conditions" be interpreted? Does compliance with R1.3.2 require multiple contingent generation unit outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be operated in accordance with the contingency definitions included in Table 1 of the TPL standards?

The following are two possible but conflicting interpretations.

1. The phrase "critical system conditions" defines a set of known or planned system conditions pertaining to load, generation dispatch, and firm transmission service reservations such as might describe summer peak, winter peak or some other assumed system conditions. Alternate generation dispatch scenarios may be evaluated. However, it is not the intent of the requirements that these alternate dispatch scenarios must include multiple contingent generation unit outages as might typically be considered to satisfy a resource adequacy planning criterion. Further, it is **not** the intent of the TPL standards that compliance requires the system to be planned to operate with multiple contingent generation unit outages as might be defined by a resource adequacy criterion **and** meet the conditions associated with contingent outages in Table 1.

2. The phrase "critical system condition" includes a variety of possible dispatch patterns including probabilistic based dispatch representative of generation deficiency scenarios with multiple contingent outages, as defined by the Transmission Planner or Planning Authority. Compliance with the TPL standard requires the application of the transmission contingency conditions in Table 1 **in addition** to these multiple contingent generation outages.

The material impacts of misinterpretation of this sub-requirement are:

- Interpretation of this sub-requirement is necessary to establish appropriate cost allocation of proposed system expansion in the Midwest ISO footprint, both within the Midwest ISO and between the Midwest ISO and PJM member companies.
- Interpretation 2 will lead to inconsistent application/interpretation of the contingency definitions included in Table 1, since the number of unit outages can vary based on the size and generation mix of each Transmission Planner's area of responsibility. As such it will be difficult to determine which contingent generation outages are part of the assumptions related to critical conditions and which are part of the contingency definitions in Table 1.
- Interpretation 2 will make compliance assessment more difficult as it relies on the judgment of the Transmission Planner or Transmission Coordinator to define which and how many contingent generator unit outages to include in the base case.
- Interpretation 2 can create a de facto transfer capability requirement.
- Interpretation 2 could dramatically increase the hurdles for the connection of new generation to system.

R.1.3.12
Questions requiring interpretation:

How should the inclusion of planned outages be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C? Does compliance with R1.3.12 require that the system be planned to operate during those conditions associated with planned outages consistent with the performance requirements described in Table 1 **plus** any unidentified planned outage?

The following are two possible but conflicting interpretations of this sub-requirement:

1. Any bulk electric equipment for which there is a known outage planned for a given point in time should be modeled as out of service in any base case model associated with the planned outage period. Such outages should not be restored prior to assessment of the applicable outage category specified by the standard. The ability to plan outages would be **accommodated** in the planning process by increasing the contingency definitions in Category B and/or Category C by one event in those studies of system conditions for which planned outages are typically performed. Standards compliance with Category B and Category C requirements would accommodate the potential planned outages through switching or redispatch so as to mitigate any limit or ratings violations.

2. In addition to known planned outages, the system shall be planned to include potential planned outages such that the system can be operated under those conditions for which planned outages are typically performed. As such, the contingency definitions associated with Category B and C events listed in Table 1 should be increased by one additional event in studies of system conditions for which planned outages are typically performed. Compliance with Category B and C events, including the addition of any potential planned outage, would be unchanged from the requirements in Table 1. Compliance with the requirement does not permit switching, redispatch or other mitigation measures to address any limit or ratings violations created by a potential planned outage for Category B events.

It should be noted that the pre Version 0 standard I.A.S2 stated that: "*...systems must be capable of meeting Category B requirements while* ***accommodating*** *the planned ... outage of any bulk electric equipment... at those demand levels for which planned... outages are performed." (emphasis added)* The I.A.S2 language regarding the ***accommodation*** of planned outages was not explicitly

captured in R.1.3.12. As such there is confusion as to how to address the issue of planned outages in the application of the TPL standards.

The material impacts of misinterpretation of this sub-requirement are:

- Interpretation of this sub-requirement is necessary to establish appropriate cost allocation of proposed system expansion in the Midwest ISO footprint, both within the Midwest ISO and between the Midwest ISO and PJM member companies.
- Interpretation 2 implies that the system should be planned such that any maintenance outage can be scheduled at demand levels for which planned outages are typically performed without the need to consider mitigation plans, alternate generation dispatch, or other outage coordination efforts which may facilitate maintenance outages.
- Interpretation 2 will result in confusion regarding appropriate contingency levels and mitigation options to be included under those conditions during which planned outages are typically planned.
- Interpretation 2 would increase the hurdles for the connection of new generation to the system by virtue of an increase in the contingency levels used in connection studies of off-peak conditions.

Thank your for your prompt consideration of these standards interpretation questions.

Sincerely,

Ed Pfeiffer
Manager, Electric Planning

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Interpretation of TPL-002-0 Requirements R1.3.2 and Requirement R1.3.12 and the identical requirements (Requirements R1.3.2 and Requirement R1.3.12) in TPL-003-0 for Ameren

Request for Interpretation of TPL-002 and TPL-003 Requirement R1.3.2 received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

R1.3.2	Cover critical system conditions and study years as deemed appropriate by the responsible entity.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002 and TPL-003 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions. The selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority/Transmission Planner.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

R1.3.12	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed are within the discretion of the Planning Authority/Transmission Planner.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Maureen E. Long
Standards Process Manager

December 4, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Three Initial Ballot Windows for Interpretations Open

The Standards Committee (SC) announces the following standards actions:

Initial Ballot Window for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren Open until 8 p.m. (EST) December 13, 2007

Ameren submitted a Request for an Interpretation of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements.

The request asked if TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 require multiple contingent generating unit outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be operated in accordance with the contingency definitions included in Table 1. The request also asked if TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 require that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

The Interpretation clarifies that TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions and clarifies that the selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority and the Transmission Planner. The interpretation also states that TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is within the discretion of the Planning Authority and the Transmission Planner.

The initial ballot for the Interpretation (for Ameren) of TPL-002 and TPL-003 is open and will remain open until 8 p.m. (EST) on Thursday, December 13, 2007.

Initial Ballot Window for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO Open until 8 p.m. (EST) December 13, 2007

MISO submitted a Request for an Interpretation of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements.

The request asked if TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asked if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios.

The request also asked if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

The Interpretation clarifies that TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions and clarifies that the selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority and the Transmission Planner. The interpretation also states that TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is within the discretion of the Planning Authority and the Transmission Planner.

The initial ballot for the Interpretation (for MISO) of TPL-002 and TPL-003 is open and will remain open until 8 p.m. (EST) on Thursday, December 13, 2007.

Initial Ballot Window for Interpretation of VAR-001-0 Requirement R4 Open until 8 p.m. (EST) December 13, 2007

Dynegy submitted a Request for an Interpretation of VAR-001-1 — Voltage and Reactive Control, Requirement R4.

The request asked if the Transmission Operator is implicitly required to have a technical basis for specifying the voltage or reactive power schedule, asked if the voltage or reactive power schedule must be reasonable and practical for the Generator Operator to maintain, and asked what measure should be used to determine if the Transmission Operator has issued a technically based, reasonable, and practical voltage or reactive power schedule.

The Interpretation clarifies that VAR-001-1 is only comprised of stated requirements and associated measures and compliance elements. Interpreting an 'implicit' requirement would effectively be adding a new requirement to the standard and needs to be achieved with a Standard Authorization Request (SAR) to modify the standard rather than through an Interpretation. There are no requirements in VAR-001-1 to issue a "technically based, reasonable, and practical to maintain voltage or reactive power schedule and associated tolerance band."

The initial ballot for the Interpretation (for Dynegy) of VAR-001 is open and will remain open until 8 p.m. (EST) on Thursday, December 13, 2007.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Ameren Services

One Ameren Plaza
1901 Chouteau Avenue
PO Box 66149
St. Louis, MO 63166-6149
314.621.3222

July 25, 2007

Maureen E. Long
Standards Process Manager
North American Electric Reliability Council
Princeton Forrestal Village
116-390 Village Boulevard
Princeton, New Jersey 08540-5721

Ameren

RE: Request for Interpretation of NERC Standards TPL-002-0 and TPL-003-0

Dear Ms. Long:

In accordance with the NERC Reliability Standards Development Procedure, I am requesting a formal interpretation of two sub-requirements which are common to NERC standards TPL-002-0 and TPL-003-0. These sub-requirements are included in R1.3 of both standards and pertain to the simulation testing to assess system performance for Category B and Category C contingencies as defined in Table 1 of the standards. The specific sub-requirements for which clarification is requested are:

> R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
>
> R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.3.2
Questions requiring interpretation:

How should the phrase "critical system conditions" be interpreted? Does compliance with R1.3.2 require multiple contingent generation unit outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be operated in accordance with the contingency definitions included in Table 1 of the TPL standards?

The following are two possible but conflicting interpretations.

1. The phrase "critical system conditions" defines a set of known or planned system conditions pertaining to load, generation dispatch, and firm transmission service reservations such as might describe summer peak, winter peak or some other assumed system conditions. Alternate generation dispatch scenarios may be evaluated. However, it is not the intent of the requirements that these alternate dispatch scenarios must include multiple contingent generation unit outages as might typically be considered to satisfy a resource adequacy planning criterion. Further, it is **not** the intent of the TPL standards that compliance requires the system to be planned to operate with multiple contingent generation unit outages as might be defined by a resource adequacy criterion **and** meet the conditions associated with contingent outages in Table 1.

2. The phrase "critical system condition" includes a variety of possible dispatch patterns including probabilistic based dispatch representative of generation deficiency scenarios with multiple contingent outages, as defined by the Transmission Planner or Planning Authority. Compliance with the TPL standard requires the application of the transmission contingency conditions in Table 1 **in addition** to these multiple contingent generation outages.

The material impacts of misinterpretation of this sub-requirement are:

- Interpretation of this sub-requirement is necessary to establish appropriate cost allocation of proposed system expansion in the Midwest ISO footprint, both within the Midwest ISO and between the Midwest ISO and PJM member companies.
- Interpretation 2 will lead to inconsistent application/interpretation of the contingency definitions included in Table 1, since the number of unit outages can vary based on the size and generation mix of each Transmission Planner's area of responsibility. As such it will be difficult to determine which contingent generation outages are part of the assumptions related to critical conditions and which are part of the contingency definitions in Table 1.
- Interpretation 2 will make compliance assessment more difficult as it relies on the judgment of the Transmission Planner or Transmission Coordinator to define which and how many contingent generator unit outages to include in the base case.
- Interpretation 2 can create a de facto transfer capability requirement.
- Interpretation 2 could dramatically increase the hurdles for the connection of new generation to system.

R.1.3.12
Questions requiring interpretation:

How should the inclusion of planned outages be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C? Does compliance with R1.3.12 require that the system be planned to operate during those conditions associated with planned outages consistent with the performance requirements described in Table 1 **plus** any unidentified planned outage?

The following are two possible but conflicting interpretations of this sub-requirement:

1. Any bulk electric equipment for which there is a known outage planned for a given point in time should be modeled as out of service in any base case model associated with the planned outage period. Such outages should not be restored prior to assessment of the applicable outage category specified by the standard. The ability to plan outages would be **accommodated** in the planning process by increasing the contingency definitions in Category B and/or Category C by one event in those studies of system conditions for which planned outages are typically performed. Standards compliance with Category B and Category C requirements would accommodate the potential planned outages through switching or redispatch so as to mitigate any limit or ratings violations.

2. In addition to known planned outages, the system shall be planned to include potential planned outages such that the system can be operated under those conditions for which planned outages are typically performed. As such, the contingency definitions associated with Category B and C events listed in Table 1 should be increased by one additional event in studies of system conditions for which planned outages are typically performed. Compliance with Category B and C events, including the addition of any potential planned outage, would be unchanged from the requirements in Table 1. Compliance with the requirement does not permit switching, redispatch or other mitigation measures to address any limit or ratings violations created by a potential planned outage for Category B events.

It should be noted that the pre Version 0 standard I.A.S2 stated that: "*…systems must be capable of meeting Category B requirements while **accommodating** the planned … outage of any bulk electric equipment… at those demand levels for which planned… outages are performed.*" *(emphasis added)* The I.A.S2 language regarding the ***accommodation*** of planned outages was not explicitly

captured in R.1.3.12. As such there is confusion as to how to address the issue of planned outages in the application of the TPL standards.

The material impacts of misinterpretation of this sub-requirement are:

- Interpretation of this sub-requirement is necessary to establish appropriate cost allocation of proposed system expansion in the Midwest ISO footprint, both within the Midwest ISO and between the Midwest ISO and PJM member companies.
- Interpretation 2 implies that the system should be planned such that any maintenance outage can be scheduled at demand levels for which planned outages are typically performed without the need to consider mitigation plans, alternate generation dispatch, or other outage coordination efforts which may facilitate maintenance outages.
- Interpretation 2 will result in confusion regarding appropriate contingency levels and mitigation options to be included under those conditions during which planned outages are typically planned.
- Interpretation 2 would increase the hurdles for the connection of new generation to the system by virtue of an increase in the contingency levels used in connection studies of off-peak conditions.

Thank your for your prompt consideration of these standards interpretation questions.

Sincerely,

Ed Pfeiffer
Manager, Electric Planning

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot of the Interpretation of Requirements R1.3.2 and R1.3.12 in TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements for Ameren

Summary Consideration: Although most balloters agreed with the interpretation, several stakeholders indicated that the interpretation doesn't adequately address the questions that were asked in the request for the interpretation. Based on these stakeholder comments, the Planning Committee, serving as the drafting team, has revised the interpretation for both R1.3.2 and R1.3.12:

> With regard to R1.3.2, the committee revised its interpretation to clearly state that the Regional Entity, as the Compliance Monitor determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner.
>
> With regard to R1.3.12, the committee revised its interpretation to clearly state that planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.1

[1] The appeals process is in the Reliability Standards Process Manual: http://www.nerc.com/standards/newstandardsprocess.html.

Voter	Entity	Segment	Vote	Comment
Kirit S. Shah Mark Peters	Ameren Services Company	1 3	Negative	Comments 1.3.2 (1) The interpretation is non-responsive to the request in that it provides no insight as to how the responsible entities should consider the requirement so as to be compliant. (2) The interpretation does not address the core issue for which interpretation was sought. The question was not intended to resolve what assumptions were to be applied to cover the critical base case conditions. Rather the question was intended to resolve whether compliance with the TPL standards shall include the consideration of non-firm incremental transfer capability, as might be modeled by multiple generator unit outages not included in the base case assumptions, in addition to the contingency scenarios defined in Table 1. Comments on R1.3.12 (1) The interpretation is non-responsive to the request in that it provides no insight as to how the responsible entities should consider the requirement so as to be compliant. (2) The interpretation is not consistent with the interpretation submitted by the NERC PC as reflected in the meeting minutes of the NERC PC.
Response: The Planning Committee thanks you for your comment. With regard to R1.3.2, the committee has revised its interpretation. The Regional Entity, as the Compliance Monitor determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. With regard to R1.3.12, the committee has revised its interpretation. Planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages.				
Brian F. Thumm	ITC Transmission	1	Negative	The choice of which planned outages to include in a study may be at the discretion of the transmission planner, but the choice of whether or not to include planned outages at all is not at their discretion. Furthermore, I find the "interpretation" to be unresponsive to the initial request. The "interpretation" does not interpret anything ... it merely restates the requirement.
Response: The Planning Committee thanks you for your comment. With regard to R1.3.12, the committee has revised its interpretation. Planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages.				

Voter	Entity	Segment	Vote	Comment
Robert G. Coish Ronald Dacombe Mark Aikens Daniel Prowse	Manitoba Hydro	1 3 5 6	Negative	The interpretation outlined in R1.3.2 accurately reflects the Planning Committee's intent; however, it likely does not provide the detail that Ameren was looking for. The interpretation for R1.3.12 does not accurately reflect the Planning Committee's intent. The interpretation for R1.3.12 fails to include the phrase 'including any necessary system adjustments prior to application of the contingency" which is critical to the NERC Planning Committee interpretation.
Response: The Planning Committee thanks you for your comment. With regard to R1.3.2, the committee has revised its interpretation. The Regional Entity, as the Compliance Monitor determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. With regard to R1.3.12, the committee has revised its interpretation. Planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages.				
Michael J Ranalli Michael Schiavone	National Grid Niagara Mohawk (National Grid Company)	1 3	Affirmative	The interpretation states "Planning Authority/Transmission Planner". The "/" can be interpreted as either an "and" or an "or". In order to be consistent with the Reliability Standard TPL-002 and TPL-003 Requirement R1, the interpretations should state "Planning Authority and Transmission Planner". Therefore we think the interpretations for TPL-002-0 and TPL-003-0 R1.3.2 and R1.3.12 should have the "/" replaced with an "and".
Response: The Planning Committee thanks you for your comment. With regard to R1.3.2, the committee has revised its interpretation. The Regional Entity, as the Compliance Monitor determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. With regard to R1.13.12, the committee has revised its interpretation. Planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages. These revised interpretations do not refer to the Planning Coordinator (formerly named the Planning Authority) or the Transmission Planner.				

Voter	Entity	Segment	Vote	Comment
Richard J. Kafka	Potomac Electric Power Co.	1	Negative	I do not believe the interpretations shown for ballot reflect the motion approved by the Planning Committee. There has been a round of emails from the Planning Committee, and the Executive Board says there was no intentional change, but I still believe the interpretation does not reflect what the PC said. In essence, what is missing, is that the PC said planning for contingencies should reflect operations in that the system would have been reconfigured (re-dispatch, switching, etc.) to provide N-1 reliability for any planned outages. That is, you don't just use the starting base case (dispatch) for all planned outages.
Response: The Planning Committee thanks you for your comment. The committee agrees and has revised its interpretation to R1.13.12. Planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages.				
Hubert C. Young	South Carolina Electric & Gas Co.	3	Negative	SCE&G believes this interpretation needs additional clarification. The NERC "Glossary of Terms" defines contingency as "The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element". A planned outage is NOT unexpected and therefore is not a contingency, based on this definition. SCE&G suggest that the standard specifically state if planned maintenance 1) is part of the event in Table 1 or 2) is a change in base conditions that are tested against Table 1. Without this clarification the industry will be planning at different levels base on individual interpretation of this standard.
Response: The Planning Committee thanks you for your comment and has revised its interpretation of R1.13.12. Planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages.				
James A. Maenner	Wisconsin Public Service Corp.	3	Negative	This interpretation is a disappointment; deferring the question back to the planning authority does not address the request for interpretation. Allowing individual Transmission Planners/Planning Authorities this discretion opens the door to wide variation across the interconnection.
Response: The Planning Committee thanks you for your comment. It is unclear if the comment provided is related to the interpretation provided for R1.3.2, R1.3.12 or a general statement related to each. In any case, we have revised our previous interpretations. With regard to R1.3.2, the committee has revised its interpretation. The Regional Entity, as the Compliance Monitor determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. With regard to R1.3.12, planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages.				

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Christopher Plante</td><td>WPS Resources Corp.</td><td>4</td><td>Negative</td><td>The "interpretation" developed for this standard essentially defers back to the Planning Authority to make its own interpretation of the standard. Allowing each Planning Authority to make its own interpretation of a Reliability Standard defeats the purpose of having a standard. NERC should strive to develop clear and concise interpretations of its Standards that do not simply defer back to the responsible entity. A much more reasonable interpretation of this standard was developed and approved by the NERC Planning Committee at their September 2007 meeting.</td></tr>
<tr><td colspan="5">Response: The Planning Committee thanks you for your comment.

With regard to R1.3.2, the committee has revised its interpretation. The Regional Entity, as the Compliance Monitor determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner.

With regard to R1.13.12, the committee has revised its interpretation. Planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages.</td></tr>
<tr><td>Karl E. Kohlrus</td><td>City Water, Light & Power of Springfield</td><td>5</td><td>Negative</td><td>The interpretation does not provide guidance as to how to determine compliance but only suggests that this requirement is subject to the discretion of the Planning Authority/Transmission Planner. As such it is unclear how to consistently and comparably assess compliance within a Planning Authority’s footprint and across NERC.</td></tr>
<tr><td colspan="5">Response: The Planning Committee thanks you for your comment.

With regard to R1.3.2, the committee has revised its interpretation. The Regional Entity, as the Compliance Monitor determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner.

With regard to R1.13.12, the committee has revised its interpretation. Planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages.</td></tr>
<tr><td>William Franklin</td><td>Entergy Services, Inc.</td><td>6</td><td>Negative</td><td>The interpretation does not adequately address the 2nd question regarding R1.3.12, and furthermore the standards do not "explicitly" provide that inclusion of the questioned activities is within the discretion of the Planning Authority/Transmission Planner.</td></tr>
<tr><td colspan="5">Response: The Planning Committee thanks you for your comment.

With regard to R1.13.12, the committee has revised its interpretation. Planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages.</td></tr>
</table>

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Ballot Results	
Ballot Name:	Interpretation Request for TPL-002-003 - Ameren_in
Ballot Period:	12/4/2007 - 12/13/2007
Ballot Type:	Initial
Total # Votes:	163
Total Ballot Pool:	188
Quorum:	86.70 % The Quorum has been reached
Weighted Segment Vote:	88.10 %
Ballot Results:	The standard will proceed to recirculation ballot.

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	59	1	43	0.878	6	0.122	4	6
2 - Segment 2.	8	0.7	7	0.7	0	0	1	0
3 - Segment 3.	49	1	32	0.78	9	0.22	1	7
4 - Segment 4.	8	0.6	5	0.5	1	0.1	1	1
5 - Segment 5.	32	1	16	0.8	4	0.2	6	6
6 - Segment 6.	17	1	12	0.857	2	0.143	0	3
7 - Segment 7.	1	0.1	1	0.1	0	0	0	0
8 - Segment 8.	2	0.2	2	0.2	0	0	0	0
9 - Segment 9.	7	0.6	6	0.6	0	0	0	1
10 - Segment 10.	5	0.4	4	0.4	0	0	0	1
Totals	**188**	**6.6**	**128**	**5.815**	**22**	**0.785**	**13**	**25**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	AEP Service Corp. -- Transmission System AEP	Scott P. Moore	Affirmative	
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services Company	Kirit S. Shah	Negative	View
1	Arizona Public Service Co.	Cary B. Deise	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott Kinney	Abstain	
1	Basin Electric Power Cooperative	David Rudolph	Negative	
1	Bonneville Power Administration	Donald S. Watkins		
1	CenterPoint Energy	Paul Rocha	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Consolidated Edison Co. of New	Edwin E. Thompson PE	Affirmative	

	York			
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	William L. Thompson	Affirmative	
1	Duke Energy Carolina	Doug Hils	Affirmative	
1	Entergy Corporation	George R. Bartlett	Negative	
1	Exelon Energy	John J. Blazekovich	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	C. Martin Mennes	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg		
1	Idaho Power Company	Ronald D. Schellberg	Abstain	
1	ITC Transmission	Brian F. Thumm	Negative	View
1	JEA	Ted E. Hobson	Affirmative	
1	Kansas City Power & Light Co.	Jim Useldinger	Affirmative	
1	Keyspan LIPA	Richard J. Bolbrock	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	Manitoba Hydro	Robert G. Coish	Negative	View
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	National Grid	Michael J Ranalli	Affirmative	View
1	Nebraska Public Power District	Richard L. Koch	Affirmative	
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Affirmative	
1	New York Power Authority	Ralph Rufrano	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Joseph Dobes	Affirmative	
1	Oncor Electric Delivery	Charles W. Jenkins	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	
1	PacifiCorp	Robert Williams	Affirmative	
1	Potomac Electric Power Co.	Richard J. Kafka	Negative	View
1	PP&L, Inc.	Ray Mammarella		
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Sacramento Municipal Utility District	Dilip Mahendra		
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Christopher M. Turner	Affirmative	
1	Southern California Edison Co.	Dana Cabbell		
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Indiana Gas and Electric Co.	Michael Chambliss	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Tri-State G & T Association Inc.	Bruce A Sembrick	Affirmative	
1	Tucson Electric Power Co.	Ronald P. Belval	Abstain	
1	Western Area Power Administration	Robert Temple	Affirmative	
2	Alberta Electric System Operator	Anita Lee	Affirmative	
2	British Columbia Transmission Corporation	Phil Park	Affirmative	

2	California ISO	David Hawkins	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Roy D. McCoy	Abstain	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
3	Alabama Power Company	Robin Hurst	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services Company	Mark Peters	Negative	View
3	American Electric Power	Raj Rana	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Negative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl		
3	City of Tallahassee	Rusty S. Foster	Affirmative	
3	City Public Service of San Antonio	Edwin Les Barrow	Affirmative	
3	Commonwealth Edison Co.	Stephen Lesniak	Affirmative	
3	Consumers Energy Co.	David A. Lapinski	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr		
3	Entergy Services, Inc.	Matt Wolf	Negative	
3	Farmington Electric Utility System	Alan Glazner	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	
3	Florida Municipal Power Agency	Michael Alexander		
3	Florida Power & Light Co.	W.R. Schoneck	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone		
3	JEA	Garry Baker	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Negative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Ronald Dacombe	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Christopher Lawrence de Graffenried	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	View
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PECO Energy an Exelon Co.	John J. McCawley		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Negative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Negative	View
3	Southern Indiana Gas and Electric Co.	Fred Frederick	Affirmative	

3	Tennessee Valley Authority	Cynthia Herron		
3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
3	Wisconsin Public Service Corp.	James A. Maenner	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	American Municipal Power - Ohio	Chris Norton	Abstain	
4	Consumers Energy Co.	David Frank Ronk	Affirmative	
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski		
4	WPS Resources Corp.	Christopher Plante	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin		
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Negative	View
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Abstain	
5	Conectiv Energy Supply, Inc.	Richard K. Douglass	Negative	
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dynegy	Greg Mason	Negative	
5	Entergy Corporation	Stanley M Jaskot		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	Douglas Keegan		
5	Florida Power & Light Co.	Robert A. Birch	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Lincoln Electric System	Dennis Florom		
5	Louisville Gas and Electric Co.	Charlie Martin	Abstain	
5	Manitoba Hydro	Mark Aikens	Negative	View
5	New York Power Authority	Richard J. Ardolino	Affirmative	
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	Reliant Energy Services	Thomas J. Bradish	Abstain	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Southeastern Power Administration	Douglas Spencer	Abstain	
5	Southern Company Services, Inc.	Roger D. Green	Affirmative	
5	Southern Indiana Gas and Electric Co.	Mark Rose	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Stephen J. Beuning		
6	AEP Service Corp.	Dana E. Horton	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson		
6	Entergy Services, Inc.	William Franklin	Negative	View
6	Exelon Power Team	Pulin Shah	Affirmative	
6	First Energy Solutions	Alfred G. Roth	Affirmative	
6	Florida Municipal Power Agency	Robert C. Williams		
6	Great River Energy	Donna Stephenson	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	PP&L, Inc.	Thomas Hyzinski	Affirmative	
6	Progress Energy Carolinas	James Eckelkamp	Affirmative	

6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Southern Company Generation and Energy Marketing	J. Roman Carter	Affirmative	
6	Southern Indiana Gas and Electric Co.	Brad Lisembee	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons		
7	Eastman Chemical Company	Lloyd Webb	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Other	Michehl R. Gent	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Public Service Commission	James T. Gallagher		
9	North Carolina Utilities Commission	Kimberly J. Jones	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Affirmative	
9	Wyoming Public Service Commission	Steve Oxley	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Midwest Reliability Organization	Larry Brusseau		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Edward A. Schwerdt	Affirmative	
10	Southwest Power Pool	Charles H. Yeung	Affirmative	

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Maureen E. Long
Standards Process Manager

December 14, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement of Initial Ballot Results for Three Interpretations

The Standards Committee (SC) announces the following:

Initial Ballot Results for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren

The initial ballot for the Interpretation (for Ameren) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements was conducted from December 4–13, 2007.

The request for interpretation asked if TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 require multiple contingent generating unit outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be operated in accordance with the contingency definitions included in Table 1. The request also asked if TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 require that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

The Interpretation clarifies that TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions and clarifies that the selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority and the Transmission Planner. The interpretation also states that TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is within the discretion of the Planning Authority and the Transmission Planner.

The ballot achieved a quorum; however, there were some negative ballots with comments, initiating the need to review the comments and determine whether the interpretation needs modification before proceeding to a re-circulation ballot. The drafting team will be reviewing comments submitted with the ballot and preparing its consideration of those comments. (Detailed Ballot Results)

Quorum: 86.70 %
Approval: 88.10 %

Initial Ballot Results for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO

The initial ballot for the Interpretation (for MISO) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements, was conducted from December 4–13, 2007.

The request for interpretation asked if TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards. MISO then asked if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios. The request also asked if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

The Interpretation clarifies that TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions and clarifies that the selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority and the Transmission Planner. The interpretation also states that TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is within the discretion of the Planning Authority and the Transmission Planner.

The ballot achieved a quorum, however there were some negative ballots with comments, initiating the need to review the comments and determine whether the interpretation needs modification before proceeding to a re-circulation ballot. The drafting team will be reviewing comments submitted with the ballot and preparing its consideration of those comments. (Detailed Ballot Results)

Quorum:	86.10 %
Approval:	87.50 %

Initial Ballot Results for Interpretation of VAR-001-0 Requirement R4 for Dynegy

The initial ballot for the Interpretation (for Dynegy) of VAR-001-0 — Voltage and Reactive Control, Requirement R4, was conducted from December 4–13, 2007.

The request for interpretation asked if the Transmission Operator is implicitly required to have a technical basis for specifying the voltage or reactive power schedule; asked if the voltage or reactive power schedule must be reasonable and practical for the Generator Operator to maintain; and asked what measure should be used to determine if the Transmission Operator has issued a technically based, reasonable and practical voltage or reactive power schedule.

The Interpretation clarifies that VAR-001-1 is only comprised of the stated requirements and associated measures and compliance elements. Interpreting an "implicit" requirement would effectively be adding a new requirement to the standard and needs to be achieved with a Standard Authorization Request (SAR) to modify the standard rather than through an Interpretation. There are no requirements in VAR-001-1 to issue a "technically based, reasonable and practical to maintain voltage or reactive power schedule and associated tolerance band."

The ballot achieved a quorum; however, there were some negative ballots with comments, initiating the need to review the comments and determine whether the interpretation needs modification before proceeding to a re-circulation ballot. The drafting team will be reviewing comments submitted with the ballot and preparing its consideration of those comments. (Detailed Ballot Results)

Quorum: 86.41 %
Approval: 93.00 %

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Interpretation of TPL-002-0 Requirement R1.3.2 and Requirement R1.3.12 and the Identical Requirements (R1.3.2 and R1.3.12) in TPL-003-0 for Ameren

Request for Interpretation of TPL-002 and TPL-003 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

> From TPL-002-0 and -003-0:
>
> [To be valid, the Planning Authority and Transmission Planner assessments shall:]
>
> **R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002 and TPL-003 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions. The selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority/Transmission Planner.

The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

> From TPL-002-0 and -003-0:
>
> [To be valid, the Planning Authority and Transmission Planner assessments shall:]
>
> **R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed are within the discretion of the Planning Authority/Transmission Planner.

The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Barbara Bogenrief

From: Barbara Bogenrief
Sent: Monday, March 24, 2008 10:34 AM
To: Barbara Bogenrief
Subject: NERC Standards Announcement - Pre-ballot Windows and Ballot Pools Open for Two Interpretations

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Pre-ballot Windows and Ballot Pools Open for Two Interpretations
March 24, 2008–April 23, 2008

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Pre-ballot Window and Ballot Pool for Revised Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren Opens March 24, 2008

Ameren submitted a Request for an Interpretation of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements.

The Planning Committee (drafting team) provided an interpretation that underwent an initial ballot from December 4–13, 2007. While the initial ballot achieved a quorum (86.70%) and a high affirmative vote (88.10%), some comments submitted with ballots indicated that the interpretation didn't fully address the questions asked, and the drafting team added some clarifying language to the interpretation. The drafting team's revised interpretation is posted for a new 30-day pre-ballot review.

The ballot pool to vote on this interpretation has been re-opened and will remain open up until 8 a.m. (EDT) Wednesday, April 23, 2008. During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." The list server for this ballot pool is: bp_Interpret_TPL_Ameren_in@ner.com

The initial ballot for this interpretation will begin at 8 a.m. (EDT) on Wednesday, April 23, 2008.

Pre-ballot Window and Ballot Pool for Revised Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO Opens March 24, 2008

MISO submitted a Request for an Interpretation of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements.

The Planning Committee (drafting team) provided an interpretation that underwent an initial ballot from December 4-13, 2007. While the initial ballot achieved a quorum (86.10%) and a high affirmative vote (87.50%), some comments submitted with ballots indicated that the interpretation didn't fully address the questions asked, and the drafting team added some clarifying language to the interpretation. The drafting team's revised interpretation is posted for a new 30-day pre-ballot review.

The ballot pool to vote on this interpretation has been re-opened and will remain open up until 8 a.m. (EDT) Wednesday, April 23, 2008. During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." The list server for this ballot pool is: bp_Interpret_TPL_MISO_in@nerc.com

The initial ballot for this interpretation will begin at 8 a.m. (EDT) on Wednesday, April 23, 2008.

Standards Development Procedure

The *Reliability Standards Development Procedure Manual* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

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July 25, 2007

Maureen E. Long
Standards Process Manager
North American Electric Reliability Council
Princeton Forrestal Village
116-390 Village Boulevard
Princeton, New Jersey 08540-5721

Ameren

RE: Request for Interpretation of NERC Standards TPL-002-0 and TPL-003-0

Dear Ms. Long:

In accordance with the NERC Reliability Standards Development Procedure, I am requesting a formal interpretation of two sub-requirements which are common to NERC standards TPL-002-0 and TPL-003-0. These sub-requirements are included in R1.3 of both standards and pertain to the simulation testing to assess system performance for Category B and Category C contingencies as defined in Table 1 of the standards. The specific sub-requirements for which clarification is requested are:

> R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
>
> R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.3.2
Questions requiring interpretation:

How should the phrase "critical system conditions" be interpreted? Does compliance with R1.3.2 require multiple contingent generation unit outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be operated in accordance with the contingency definitions included in Table 1 of the TPL standards?

The following are two possible but conflicting interpretations.

1. The phrase "critical system conditions" defines a set of known or planned system conditions pertaining to load, generation dispatch, and firm transmission service reservations such as might describe summer peak, winter peak or some other assumed system conditions. Alternate generation dispatch scenarios may be evaluated. However, it is not the intent of the requirements that these alternate dispatch scenarios must include multiple contingent generation unit outages as might typically be considered to satisfy a resource adequacy planning criterion. Further, it is **not** the intent of the TPL standards that compliance requires the system to be planned to operate with multiple contingent generation unit outages as might be defined by a resource adequacy criterion **and** meet the conditions associated with contingent outages in Table 1.

2. The phrase "critical system condition" includes a variety of possible dispatch patterns including probabilistic based dispatch representative of generation deficiency scenarios with multiple contingent outages, as defined by the Transmission Planner or Planning Authority. Compliance with the TPL standard requires the application of the transmission contingency conditions in Table 1 **in addition** to these multiple contingent generation outages.

The material impacts of misinterpretation of this sub-requirement are:

- Interpretation of this sub-requirement is necessary to establish appropriate cost allocation of proposed system expansion in the Midwest ISO footprint, both within the Midwest ISO and between the Midwest ISO and PJM member companies.
- Interpretation 2 will lead to inconsistent application/interpretation of the contingency definitions included in Table 1, since the number of unit outages can vary based on the size and generation mix of each Transmission Planner's area of responsibility. As such it will be difficult to determine which contingent generation outages are part of the assumptions related to critical conditions and which are part of the contingency definitions in Table 1.
- Interpretation 2 will make compliance assessment more difficult as it relies on the judgment of the Transmission Planner or Transmission Coordinator to define which and how many contingent generator unit outages to include in the base case.
- Interpretation 2 can create a de facto transfer capability requirement.
- Interpretation 2 could dramatically increase the hurdles for the connection of new generation to system.

R.1.3.12
Questions requiring interpretation:

How should the inclusion of planned outages be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C? Does compliance with R1.3.12 require that the system be planned to operate during those conditions associated with planned outages consistent with the performance requirements described in Table 1 **plus** any unidentified planned outage?

The following are two possible but conflicting interpretations of this sub-requirement:

1. Any bulk electric equipment for which there is a known outage planned for a given point in time should be modeled as out of service in any base case model associated with the planned outage period. Such outages should not be restored prior to assessment of the applicable outage category specified by the standard. The ability to plan outages would be **accommodated** in the planning process by increasing the contingency definitions in Category B and/or Category C by one event in those studies of system conditions for which planned outages are typically performed. Standards compliance with Category B and Category C requirements would accommodate the potential planned outages through switching or redispatch so as to mitigate any limit or ratings violations.

2. In addition to known planned outages, the system shall be planned to include potential planned outages such that the system can be operated under those conditions for which planned outages are typically performed. As such, the contingency definitions associated with Category B and C events listed in Table 1 should be increased by one additional event in studies of system conditions for which planned outages are typically performed. Compliance with Category B and C events, including the addition of any potential planned outage, would be unchanged from the requirements in Table 1. Compliance with the requirement does not permit switching, redispatch or other mitigation measures to address any limit or ratings violations created by a potential planned outage for Category B events.

It should be noted that the pre Version 0 standard I.A.S2 stated that: "*…systems must be capable of meeting Category B requirements while **accommodating** the planned ... outage of any bulk electric equipment… at those demand levels for which planned… outages are performed.*" *(emphasis added)* The I.A.S2 language regarding the ***accommodation*** of planned outages was not explicitly

captured in R.1.3.12. As such there is confusion as to how to address the issue of planned outages in the application of the TPL standards.

The material impacts of misinterpretation of this sub-requirement are:

- Interpretation of this sub-requirement is necessary to establish appropriate cost allocation of proposed system expansion in the Midwest ISO footprint, both within the Midwest ISO and between the Midwest ISO and PJM member companies.
- Interpretation 2 implies that the system should be planned such that any maintenance outage can be scheduled at demand levels for which planned outages are typically performed without the need to consider mitigation plans, alternate generation dispatch, or other outage coordination efforts which may facilitate maintenance outages.
- Interpretation 2 will result in confusion regarding appropriate contingency levels and mitigation options to be included under those conditions during which planned outages are typically planned.
- Interpretation 2 would increase the hurdles for the connection of new generation to the system by virtue of an increase in the contingency levels used in connection studies of off-peak conditions.

Thank your for your prompt consideration of these standards interpretation questions.

Sincerely,

Ed Pfeiffer
Manager, Electric Planning

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Interpretation of TPL-002-0 Requirement R1.3.2 and Requirement R1.3.12 and the Identical Requirements (R1.3.2 and R1.3.12) in TPL-003-0 for Ameren

Request for Interpretation of TPL-002 and TPL-003 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

From TPL-002-0 and -003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002 and TPL-003 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions. The selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority/Transmission Planner.

The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

From TPL-002-0 and -003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed are within the discretion of the Planning Authority/Transmission Planner.

The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Barbara Bogenrief

From: Barbara Bogenrief [Barbara.Bogenrief@nerc.net]
Sent: Thursday, April 24, 2008 9:33 AM
To: Barbara Bogenrief
Subject: NERC Standards Announcement - Ballot Window Opens for Two Interpretations

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Ballot Window Opens for Two Interpretations
April 25–May 5, 2008

Now available at: http://www.nerc.com/~filez/standards/Reliability_Standards_Under_Development.html

Ballot Window for Revised Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren Opens Friday, April 25, 2008

The initial ballot for the revised interpretation (for Ameren) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements, will open at 8 a.m. (EDT) on Friday, April 25, 2008.

The Planning Committee (drafting team) provided an interpretation that underwent an initial ballot from December 4–13, 2007. While the initial ballot achieved a quorum (86.70%) and a high affirmative vote (88.10%), some comments submitted with ballots indicated that the interpretation didn't fully address the questions asked, and the drafting team added some clarifying language to the interpretation. The initial ballot for the revised interpretation will close at 8 p.m. (EDT) on Monday, May 5, 2008.

Ballot Window for Revised Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO Opens Friday, April 25

The initial ballot for the revised interpretation (for MISO) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements, will open at 8 a.m. (EDT) on Friday, April 25, 2008.

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Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

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July 25, 2007

Maureen E. Long
Standards Process Manager
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Ameren

RE: Request for Interpretation of NERC Standards TPL-002-0 and TPL-003-0

Dear Ms. Long:

In accordance with the NERC Reliability Standards Development Procedure, I am requesting a formal interpretation of two sub-requirements which are common to NERC standards TPL-002-0 and TPL-003-0. These sub-requirements are included in R1.3 of both standards and pertain to the simulation testing to assess system performance for Category B and Category C contingencies as defined in Table 1 of the standards. The specific sub-requirements for which clarification is requested are:

> R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
>
> R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.3.2
Questions requiring interpretation:

How should the phrase "critical system conditions" be interpreted? Does compliance with R1.3.2 require multiple contingent generation unit outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be operated in accordance with the contingency definitions included in Table 1 of the TPL standards?

The following are two possible but conflicting interpretations.

1. The phrase "critical system conditions" defines a set of known or planned system conditions pertaining to load, generation dispatch, and firm transmission service reservations such as might describe summer peak, winter peak or some other assumed system conditions. Alternate generation dispatch scenarios may be evaluated. However, it is not the intent of the requirements that these alternate dispatch scenarios must include multiple contingent generation unit outages as might typically be considered to satisfy a resource adequacy planning criterion. Further, it is **not** the intent of the TPL standards that compliance requires the system to be planned to operate with multiple contingent generation unit outages as might be defined by a resource adequacy criterion **and** meet the conditions associated with contingent outages in Table 1.

2. The phrase "critical system condition" includes a variety of possible dispatch patterns including probabilistic based dispatch representative of generation deficiency scenarios with multiple contingent outages, as defined by the Transmission Planner or Planning Authority. Compliance with the TPL standard requires the application of the transmission contingency conditions in Table 1 **in addition** to these multiple contingent generation outages.

The material impacts of misinterpretation of this sub-requirement are:

- Interpretation of this sub-requirement is necessary to establish appropriate cost allocation of proposed system expansion in the Midwest ISO footprint, both within the Midwest ISO and between the Midwest ISO and PJM member companies.
- Interpretation 2 will lead to inconsistent application/interpretation of the contingency definitions included in Table 1, since the number of unit outages can vary based on the size and generation mix of each Transmission Planner's area of responsibility. As such it will be difficult to determine which contingent generation outages are part of the assumptions related to critical conditions and which are part of the contingency definitions in Table 1.
- Interpretation 2 will make compliance assessment more difficult as it relies on the judgment of the Transmission Planner or Transmission Coordinator to define which and how many contingent generator unit outages to include in the base case.
- Interpretation 2 can create a de facto transfer capability requirement.
- Interpretation 2 could dramatically increase the hurdles for the connection of new generation to system.

R.1.3.12
Questions requiring interpretation:

How should the inclusion of planned outages be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C? Does compliance with R1.3.12 require that the system be planned to operate during those conditions associated with planned outages consistent with the performance requirements described in Table 1 **plus** any unidentified planned outage?

The following are two possible but conflicting interpretations of this sub-requirement:

1. Any bulk electric equipment for which there is a known outage planned for a given point in time should be modeled as out of service in any base case model associated with the planned outage period. Such outages should not be restored prior to assessment of the applicable outage category specified by the standard. The ability to plan outages would be **accommodated** in the planning process by increasing the contingency definitions in Category B and/or Category C by one event in those studies of system conditions for which planned outages are typically performed. Standards compliance with Category B and Category C requirements would accommodate the potential planned outages through switching or redispatch so as to mitigate any limit or ratings violations.

2. In addition to known planned outages, the system shall be planned to include potential planned outages such that the system can be operated under those conditions for which planned outages are typically performed. As such, the contingency definitions associated with Category B and C events listed in Table 1 should be increased by one additional event in studies of system conditions for which planned outages are typically performed. Compliance with Category B and C events, including the addition of any potential planned outage, would be unchanged from the requirements in Table 1. Compliance with the requirement does not permit switching, redispatch or other mitigation measures to address any limit or ratings violations created by a potential planned outage for Category B events.

It should be noted that the pre Version 0 standard I.A.S2 stated that: "*…systems must be capable of meeting Category B requirements while **accommodating** the planned ... outage of any bulk electric equipment… at those demand levels for which planned… outages are performed.*" *(emphasis added)* The I.A.S2 language regarding the ***accommodation*** of planned outages was not explicitly

captured in R.1.3.12. As such there is confusion as to how to address the issue of planned outages in the application of the TPL standards.

The material impacts of misinterpretation of this sub-requirement are:

- Interpretation of this sub-requirement is necessary to establish appropriate cost allocation of proposed system expansion in the Midwest ISO footprint, both within the Midwest ISO and between the Midwest ISO and PJM member companies.
- Interpretation 2 implies that the system should be planned such that any maintenance outage can be scheduled at demand levels for which planned outages are typically performed without the need to consider mitigation plans, alternate generation dispatch, or other outage coordination efforts which may facilitate maintenance outages.
- Interpretation 2 will result in confusion regarding appropriate contingency levels and mitigation options to be included under those conditions during which planned outages are typically planned.
- Interpretation 2 would increase the hurdles for the connection of new generation to the system by virtue of an increase in the contingency levels used in connection studies of off-peak conditions.

Thank your for your prompt consideration of these standards interpretation questions.

Sincerely,

Ed Pfeiffer
Manager, Electric Planning

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot of Revised Interpretation of TPL-002 and TPL-003 — Requirements 1.3.2 and 1.3.12 for Ameren

Summary Consideration: The drafting team corrected a typographical error in the last paragraph of the interpretation, but did not make any other modifications to the interpretation based on the comments submitted.

Correction:
TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is required.

Segment	Organization	Comment
1	Ameren Services Company	TPL-002-0 Requirement R.1.3.2: Do Not Approve. Comments: The proposed interpretation of R1.3.2 does not answer the following basic question with respect to the TPL standards: Does including contingent outages as part of the defined operating state exceed the contingency requirements specified in Table 1 of the TPL standards? Defining contingent outages in the assumed system operating state is not consistent with FAC or TPL standards. FAC-010 specifies in Requirement R2.1 In the pre-contingency state with all Facilities in service TPL-002-0 Requirement R1 provides the general description for the reliability assessment of the system. R1 states that the system shall be studied under the contingency conditions as defined in Category B of Table 1. How does the interpretation address the inconsistency of modeling contingent outages as critical system conditions outside of Table 1? Could a Transmission Planner or Planning Coordinator (Authority) specify one or more contingent transmission facility outages in their critical system conditions? The contentious application of “critical system conditions” did not apply to the specification of a base case dispatch scenario. The Planning Coordinator performed a First Contingency Incremental Transfer Capability (FCITC) analysis which modeled non-firm transactions to replace contingent generation outages. Does compliance with TLP-002 require sufficient import capability to provide access to external generation capacity for which there are not explicit capacity or transmission reservations at the discretion of the Planning Coordinator? FAC-012-1, Transfer Capability Methodology, requires that the Planning Coordinator (Authority) to document its current methodology used for developing its inter-regional and intra-regional Transfer Capabilities (Transfer Capability Methodology). Does this interpretation suggest that the Planning Coordinator has the requirement or responsibility to define a minimum level of transfer capability? Is it the intent of this interpretation that a Planning Coordinator’s transfer capability methodology be applied to TPL standards compliance? The draft interpretation states that the selection of a credible generation dispatch for modeling of critical system conditions is within the discretion of the

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<table>
<tr><th>Segment</th><th>Organization</th><th>Comment</th></tr>
<tr><td></td><td></td><td>Planning Coordinator: which of the current standards establishes a requirement that the Planning Coordinator develop a methodology to determine base case dispatch scenarios or gives the Planning Coordinator the authority to prescribe dispatch assumptions?</td></tr>
<tr><td colspan="3">Response: We thank you for your comments, which address R1.3.2. However, most of the questions posed go well beyond the subject matter of the interpretation.

The term “critical system conditions” is undefined in TPL-002 and TPL-003, and the standard itself gives no basis for defining it. Neither does the Functional Model, a standards reference document, provide any guidance. While this is understandably what Ameren is seeking in their comments, our interpretation could not provide a direct answer. However, we were able to articulate a process for obtaining the specificity desired by Ameren, which we reiterate below.

The Functional Model language cited in the interpretation supports the Planning Coordinator’s supervisory role in directing the coordination of the planning process, including the specification of any methodologies to be used by Transmission Planners in its area. Such authority is also implied by a common sense reading of the standard itself. Assume that the standard was written with the understanding that the Planning Coordinator did not have this authority. Each of its Transmission Planners would be free to make adopt their own methods, and the Planning Coordinator’s assessment as well as each Transmission Planner’s assessment would be invalid on its face due solely to the lack of coordination. (Remember that M1 and M2 apply to both the Planning Coordinator and its Transmission Planners.)

As we stated in the interpretation “As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters."</td></tr>
<tr><td>1</td><td>American Transmission Company, LLC</td><td>The interpretation applies to only the Planning Coordinator while the standard R1 applies to both the Planning Coordinator and Transmission Planner. ATC believes that the proposed interpretation is assigning greater authority onto the Planning Coordinator than the requirement specifies. Lastly, ATC believe that the Functional Model Reference Document should not be used for an interpretation. (What happens if the Functional Model document is changed so that it no long supports an interpretation?)</td></tr>
<tr><td colspan="3">Response: We thank you for your comments, which address R1.3.2. We respectively disagree with ATC’s statement that “the proposed interpretation is assigning greater authority onto the Planning Coordinator <u>than the requirement specifies</u> (emphasis added).” The relationship between the Planning Coordinator and its Transmission Planners is not specified in any requirement in TPL-002 or TPL-003.

The Functional Model language cited in the interpretation supports the Planning Coordinator’s supervisory role in directing the coordination of the planning process, including the specification of any methodologies to be used by Transmission Planners in its area. The Functional Model is a reference document, and as such it may be used to support the interpretation of a Reliability Standard. See NERC’s Rules of Procedures, Appendix 3A, p. 34. We have referenced a specific Functional Model version 3, not the current Functional Model, so our interpretation would not change if the Functional Model changed.</td></tr>
</table>

Segment	Organization	Comment
Such authority is also implied by a common sense reading of the standard itself, even without a reference to the Functional Model. Assume that the standard was written with the understanding that the Planning Coordinator *did not* have this authority. Each of its Transmission Planners would be free to make and adopt its own methods, and the Planning Coordinator's assessment as well as each Transmission Planner's assessment would be invalid on its face due solely to the lack of coordination. (Remember that M1 and M2 apply to both the Planning Coordinator *and* its Transmission Planners.)		
1	Duke Energy Carolina	Thank you for the opportunity to vote on this interpretation. We agreed with the September 12, 2007 Interpretation of Requirement 1.3.2, but do not agree with the March 13, 2008 Interpretation of Requirement 1.3.2, which places selection of critical system conditions under the authority of the Planning Coordinator. We agreed with the September 12, 2007 Interpretation of Requirement 1.3.12, and also agree with the March 13, 2008 Interpretation of Requirement 1.3.12.
Response: We thank you for your comments. However, since you offer no explanation as to why you disagree with R1.3.2, we can offer no response.		
1	Entergy Corporation	There are requirements in the standard that we feel are applied equally to the Transmission Planner and the Planning Coordinator. We believe that the interpretation erroneously attributes approval authority to the PC and the RE that is not called out for in the standard.
Response: We thank you for your comments. The relationship between the Planning Coordinator and the Transmission Planner is not specified in any of the requirements in TPL-002 or TPL-003. The Functional Model language cited in the interpretation supports the Planning Coordinator's supervisory role in directing the coordination of the planning process, including the specification of any methodologies to be used by Transmission Planners in its area. The Functional Model is a reference document, and as such it may be used to support the interpretation of a Reliability Standard. See NERC's *Rules of Procedures*, Appendix 3A, p. 34. We have referenced a specific Functional Model version 3, not the current Functional Model, so our interpretation would not change if the Functional Model changed. Such authority is also implied by a common sense reading of the standard itself, even without a reference to the Functional Model. Assume that the standard was written with the understanding that the Planning Coordinator *did not* have this authority. Each of its Transmission Planners would be free to make and adopt its own methods, and the Planning Coordinator's assessment as well as each Transmission Planner's assessment would be invalid on its face due solely to the lack of coordination. (Remember that M1 and M2 apply to both the Planning Coordinator *and* its Transmission Planners.)		
1	Gainesville Regional Utilities	I suggest the first sentence ending be changed from "are required" to "are performed within the discretion of the Planning Authority/Transmission Planner." This change will return the standard to its original interpretation concerning this matter and keep the volume of work hopefully within achievable limits. Secondly, the second sentence raised a concern that a planned outage should be considered a contingency which totally goes against the NERC

<table>
<tr><th>Segment</th><th>Organization</th><th>Comment</th></tr>
<tr><td></td><td></td><td>Glossary of Terms. You must allow some necessary system adjustments to accommodate this condition before running any contingency studies.</td></tr>
<tr><td colspan="3">Response: We thank you for your comments, which address R1.3.12. We respectfully disagree with your suggested change in the first sentence which would make the consideration of planned outages within the discretion of the Planning Authority/Transmission Planner. R.1.3.12 is a requirement, and as such, cannot be optional or discretionary. However, the requirement does not specify a method for the modeling of planned outages; such modeling methods are within the discretion of the Planning Authority [Planning Coordinator] to specify, and those methods should be consistently used by all its Transmission Planners.

We believe that Gainesville has misread our second sentence. We stated that a “planned outage is <u>not</u> [emphasis added] a “contingency” and that “necessary system adjustments” would be included prior to any contingency assessment.</td></tr>
<tr><td>1</td><td>Manitoba Hydro</td><td>Manitoba Hydro agrees with the interpretation outlined in TPL-003-0 R1.3.12; however, Manitoba Hydro does not agree with the interpretation of TPL-002-0 and TPL-003-0 R1.3.2. The standard puts the onus of defining critical system conditions on the PA/TP. The revised interpretation creates confusion as it is now unclear as to whether the PA/TP or RE as Compliance monitor is to determine the critical system conditions.</td></tr>
<tr><td colspan="3">Response: We thank you for your comments. We respectfully disagree with your conclusion regarding our interpretation of R1.3.2. The Planning Coordinator has the authority to specify “critical system conditions.” As we stated in the interpretation “As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters."</td></tr>
<tr><td>1</td><td>Northeast Utilities</td><td>There remains a necessary level of coordination between the Transmission Planner and Planning Authority to determine generation dispatch and planned outage scenarios to be used in system assessments. The revised interpretation disregards the important role of the Transmission Planner, which the Standards themselves do not. Additionally, we believe NERC has not followed its Reliability Standards Development Procedure (Version 6.1) which in Step 9, First Ballot section, the last paragraph states; however, one or more members submit negative votes with reasons, regardless whether those reasons are resolved or not, a second ballot shall be conducted. NERC failed to follow this step. Further, in Step 9, Second Ballot section, the 3rd paragraph states; In the second ballot step, no revisions to the standard are permitted; as such revisions would not have been subject to public comment. However, if the Standards Committee determines that revisions proposed during the ballot process would likely provide an opportunity to achieve consensus on the standard, then such revisions may be made and the draft standard posted for public comment again beginning with Step 6 and continuing with subsequent steps. NERC has revised the interpretations (contrary to the 1st sentence) and has not posted for public comment again beginning with Step 6 (contrary to the 2nd). It did not seem necessary to revise interpretations for which, from an 86.7% quorum, 88.1% voted</td></tr>
</table>

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		affirmative.
Response: We thank you for your comment, which addresses R1.3.2. We respectfully disagree that we have disregarded the role of the Transmission Planner. We have, however, clarified the relationship between the Planning Coordinator and the Transmission Planner. We did not proceed with a second ballot on the original interpretation because we agreed with many of the negative comments and therefore elected to revise the original interpretation instead of proceeding with a recirculation ballot. The procedure cited presumes that the comments received do not affect the standard drafting team's views on the balloted standard. In other words, it assumes that the comments do not cause the team to withdraw and revise the standard that was balloted. In our case, the comments we received in the first ballot caused us to revise our interpretation. Although the standards process does require that draft standards be posted for comment, the standards process does not require that interpretations be posted for comment. Interpretations are developed by a team and then posted for a 30-day pre-ballot review – there is no comment period for an interpretation.		
1	Omaha Public Power District	The first sentence of the revised interpretation of TPL-002 and TPL-003 R1.3.12 is actually not a complete sentence, and as a result, it is impossible to understand it. The revised interpretation therefore should not be approved in its current form. Did the Planning Committee intend to insert the words "performed is" before the word "required" in the first sentence?
Response: We agree. This appears to be a typographical error, and we will modify the first sentence by inserting the phrase "performed is" as shown: "TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are <u>performed is</u> required.		
1	Pacific Gas and Electric Company	While I agree with Interpretation 1 in that TPL standards are not meant for planning for resource adequacy. We do not necessarily disagree with Interpretation 2 because it seems to describe a planning methodology. I voted affirmative because NERC Standard is to specify what the requirements are and not how to meet them.
Response: No response is required.		
1	Sacramento Municipal Utility District	In explaining the revised interpretation for R1.3.2, that, "selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority", the interpretation dilutes the discretion given in subsequent paragraphs. Specifically, it states the "Planning Coordinator would formulate critical system conditions" and that the "the RE determines what a "valid assessment" means". The word 'formulate' is much weaker than what is stated in the requirement R1.3.2 - "as deemed appropriate" by the planning coordinator/transmission planner. The new interpretation implies that until the 'regional entity' (WECC) approves our assessment, it is not valid. I do not believe that is the requirement. The new interpretation goes beyond the stated requirement. Determining a valid assessment should stay independent of who (PA or RE) is doing it.
Response: We thank you for your comment. Our statement that the "Planning Coordinator would formulate critical system conditions" is not in conflict with our earlier statement that the "selection of critical generation dispatch for the modeling of critical system conditions is within the		

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discretion of the Planning Authority." Neither is the "would formulate" language any weaker that the "as deem appropriate" language in R.1.3.2. We have not altered this requirement. The Planning Coordinator would formulate the critical system conditions it deemed appropriate. With regards to the second comment regarding the role of the Regional Entity, in a sense an RE does "approve" a Planning Coordinator's assessment since by not issuing a compliance violation, it has determined that measures M1 and M2 are satisfied; i.e., that the assessment is valid and that it has been properly reported. (Some REs may provide affirmative approval, so that a Planning Coordinator or Transmission Planner knows that its assessment has been approved). However, an RE's obligation to determine whether an assessment is "valid" does not allow the RE to micromanage the assessments it reviews. For example, it cannot reject a corrective plan (e.g., the proposed construction of new facilities) because it believes another plan would be more cost effective. If the proposed corrective plan fulfills the standard's requirements, it is not reviewable by the RE. Finally, we did not state that an RE performed assessments as your last sentence implies.		
1	Salt River Project	R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity. Although SRP agrees that the Planning Authority (PA) shall have the discretion in choosing the appropriate conditions to study for their system(s), we disagree with the language as stated. There is no definition of how or what a PA shall do in the "methodology." Methodology is not described in any Standard to this point. Therefore, how could compliance be measured? Methodology needs to be described or enumerated to be applied in Standards and for compliance. R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed. SRP agrees with the revised interpretation of TPL-002-0 and TPL-003-0 R1.3.12 as developed by the NERC Planning Committee on March 12, 2008.
Response: We thank you for your comment. We agree that a methodology for defining "critical system conditions" is not part of TPL-002 and TPL-003. The reference to "methodology in the interpretation comes from the Functional Model language we cited, and that citation states that the Planning Coordinator "provides…Transmission Planners …methodologies and tools for the simulation of the transmission system." We further state that a "PC's selection of "critical system conditions" fall within the purview of "methodology." We use this citation to establish the Planning Coordinators authority for specifying "critical system conditions" which it determines are appropriate. The standards to do not require a methodology, and our interpretation does not require one.		
1	Southern Indiana Gas and Electric Co.	The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008: TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL- 002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might

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		be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the NERC Glossary of Terms Used in Standards. Vectren requests that consideration be given to change the verbiage; "include any necessary system adjustments" to include the word "reasonable" or some other similar word to limit the system adjustments. The suggested verbiage would then read "include any reasonable and necessary system adjustments". Vectren does not believe that the word "necessary" provides enough limitation to the adjustments that should be considered. If the system adjustment necessary to eliminate an overload caused by the planned outage combined with contingency assessment requires an unreasonable amount of generation redispatch or the dropping of firm load, there should be some ability for the Transmission Planner or the Planning Authority to make the determination that the adjustment is unreasonable and another remedy for the overload must be explored. Your consideration in this matter is appreciated.
Response: We thank you for your comment, which addresses R1.3.12. We do not believe that the addition of the word “reasonable” has additional interpretative value. The language posed by Southern Indiana Gas and Electric Co. is an attempt to remove load shedding as a possible “necessary system adjustment” prior to modeling a contingency assessment. We do not believe that the word “reasonable” will accomplish this goal, nor do we believe it is required. It is not required because we do not believe that load shedding would ever be considered a “necessary system adjustment which might be required to accommodate planned outages” as our interpretation states. In support of this conclusion, consider TPL-002. It does not permit the loss of demand except as noted in footnote “b.” If a Planning Coordinator or Transmission Planner attempted to “pass” TPL-002 by *a priori* load shedding under the guise of a “necessary system adjustment” for a planned outage, it would have shed load in order to comply with a standard that does not permit load shedding, and we would expect the RE reviewing the assessment to find it invalid.		
1	Tucson Electric Power Co.	The language in the Request for Interpretation is not clear. TEP requests clarification as to how planned outages are to be addressed. We believe planned outages, to the extent they may be known, should be treated as post-N-1 with system adjusted similar to the first event in a Category C 3 event wherein system adjustment is allowed following the outage. A distinction in the case of a planned outage may be made in that system adjustment would be implemented prior to taking the outage. In either case, system adjustment may include running generation, arming load shed for subsequent single contingencies, and/or other appropriate measures in preparation for the next event. This is important, as longer-term planned outages would include those outages needed to get system upgrades built and commissioned. Outages required to implement system upgrades should not be subjected to the same requirements as conditions with all facilities in service.
Response: We thank you for your comment, which addresses R1.3.12. Planned outages are modeled such that after the planned outage *and* any necessary system adjustments, the system is able to withstand a Category B event with Category B results. Therefore, the “necessary system adjustments” for the planned outage are taken *before* the planned outage.		

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Although a Category C 3 contemplates system adjustments *after* the first Category B event, it is not the same as a planned outage followed by a Category B event. For a Category C 3 event, the system adjustments may be "in progress" and not fully completed before the next Category B event occurs, whereas for planned outages those adjustments have been completed. Finally, a Category C 3 event permits the interruption of customers, whereas a Category B does not except as noted in footnote "b." If a planned outage were followed by a Category B event, no load loss except as noted in footnote "b" would be permitted.		
2	British Columbia Transmission Corporation	R1.3.2 The first sentence of the response is acceptable, although it could be made clearer. We suggest that the appropriate response to the question would be: R1.3.2 does not require multiple contingent generating unit outages as part of the possible generation dispatch scenarios. However, it also does not preclude this if the Planning Coordinator deems that consideration of such condition is appropriate. The last paragraph is unacceptable because it states that the Compliance Monitor determines what a "valid assessment" means. This is incorrect. The TPL standard states what a valid assessment includes. The Compliance Monitor role is to audit whether the PC's assessment includes the elements of a "valid assessment" and prescribed in the standard. R1.3.12 The statement made in the 13 March response is a correct statement. However, we do not understand the question, but do not believe the 13 March response answers the question. Since we do not understand the question, we do not know what an appropriate response would be.
Response: We thank you for your comment, which addresses R1.3.2 and R1.3.12. With regards to R1.3.2, we disagree with your statement that the Compliance Monitor does not determine whether an assessment is "valid." That is what its auditing of compliance requires. However, an RE's obligation to determine whether an assessment is "valid" does not allow the RE to micromanage the assessments it reviews. For example, it cannot reject a corrective plan (e.g., the proposed construction of new facilities) because it believes another plan would be more cost effective. If the proposed corrective plan fulfills the standard's requirements, it is not reviewable by the RE. British Columbia Transmission Corporation said it did not understand the question posed in R1.3.12. While it was in the interpretation, we have restated below: *Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*		
2	Midwest ISO, Inc.	The Re-interpretation states in part: ** For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the NERC Glossary of

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		Terms Used in Standards. ** With regard to the revised interpretation, the Midwest ISO does not agree with the revised interpretation and at a minimum recommends the following modification in double quotation marks, for the reasons described below. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 may include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the NERC Glossary of Terms Used in Standards. ""In the alternative, if the PA or TP elected not to model in planning studies all available system adjustments and instead opted to upgrade the system to meet system performance, this would be acceptable under the requirements of the standard."" By stating that compliance would include any necessary system adjustments, this could be interpreted as non-compliance if in the discretion of the TP or PA, planning studies tested the system without applying all available system adjustments and therefore resulted in the construction of a more reliable system. It is inconceivable that NERC would judge an entity non-compliant with reliability standards for developing a more reliable system. Midwest ISO further believes strongly that the original interpretation was appropriate in articulating the discretion that TPs and PAs must have in planning their systems to be able to reasonably accommodate planned outages. Planning is performed years in advance in order that the system operator in real time will have a system that will perform reliably. All systems should be planned to be robust enough so that reasonable planned outages can be taken during typical maintenance periods (e.g. spring and fall) without the need for excessive redispatch or other operating steps merely to be able to withstand the next contingency. Large systems that include multiple separate sub-systems in close electrical proximity and with potentially redispatchable generation involving many different generation owners, must be planned to accommodate multiple planned outages on these adjoining systems. The Planning Authority over such a system must have the discretion to determine based on planning data and operating experience whether or not the interconnected system under its authority is robust enough to be able to take reasonable planned outages in several interconnected sub-systems with adequate reliability margin, and without having to resort to excessive redispatch or other operating steps in order to accommodate such planned outages. The PA may consider as excessive, for example, having to redispatch large amounts of base-load generation, or generation that does not belong to the entity taking the planned outage, or having to redispatch for a large number of separate possible planned outage conditions. The original interpretation appropriately supports this kind of discretion on the part of the PA.
Response: We thank you for your comments. The requested added language ("In the alternative, if the PA or TP elected not to model in planning studies all available system adjustments and instead opted to upgrade the system to meet system performance, this would be acceptable under the requirements of the standard.") is unacceptable for two reasons. First, our interpretation does not require “all available		

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system adjustments"; it requires only the "necessary system adjustments which might be required to accommodate the planned outages." Second, the alternative language addresses a corrective plan (i.e., upgrade the system) and not the performance of the system. It is important that a standard not comingle a corrective plan with a performance requirement. The improper modeling of system adjustments is not made acceptable by an upgrade that may not have been required if system adjustments had been properly modeled.		
3	Ameren Services Company	TPL-002-0 Requirement R.1.3.2 : Do Not Approve. The proposed interpretation of R1.3.2 does not answer the following basic question with respect to the TPL standards: Does including contingent outages as part of the defined operating state exceed the contingency requirements specified in Table 1 of the TPL standards? Defining contingent outages in the assumed system operating state is not consistent with FAC or TPL standards. FAC-010 specifies in Requirement R2.1. In the pre-contingency state with all Facilities in service TPL-002-0 Requirement R1 provides the general description for the reliability assessment of the system. R1 states that the system shall be studied under the contingency conditions as defined in Category B of Table 1. How does the interpretation address the inconsistency of modeling contingent outages as critical system conditions outside of Table 1? Could a Transmission Planner or Planning Coordinator (Authority) specify one or more contingent transmission facility outages in their critical system conditions? The contentious application of "critical system conditions" did not apply to the specification of a base case dispatch scenario. The Planning Coordinator performed a First Contingency Incremental Transfer Capability (FCITC) analysis which modeled non-firm transactions to replace contingent generation outages. Does compliance with TLP-002 require sufficient import capability to provide access to external generation capacity for which there are not explicit capacity or transmission reservations at the discretion of the Planning Coordinator? â€¢ FAC-012-1, Transfer Capability Methodology, requires that the Planning Coordinator (Authority) to document its current methodology used for developing its inter-regional and intra-regional Transfer Capabilities (Transfer Capability Methodology). Does this interpretation suggest that the Planning Coordinator has the requirement or responsibility to define a minimum level of transfer capability? Is it the intent of this interpretation that a Planning Coordinator's transfer capability methodology be applied to TPL standards compliance? â€¢ The draft interpretation states that the selection of a credible generation dispatch for modeling of critical system conditions is within the discretion of the Planning Coordinator: which of the current standards establishes a requirement that the Planning Coordinator develop a methodology to determine base case dispatch scenarios or gives the Planning Coordinator the authority to prescribe dispatch assumptions?
Response: We thank you for your comments, which address R1.3.2. However, most of the questions posed go well beyond the subject matter of the interpretation. The term "critical system conditions" is undefined in TPL-002 and TPL-003, and the standard itself gives no basis for defining it. Neither does		

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the Functional Model, a standards reference document, provide any guidance. While this is understandably what Ameren is seeking in their comments, our interpretation could not provide a direct answer. However, we were able to articulate a process for obtaining the specificity desired by Ameren, which we reiterate below. The Functional Model language cited in the interpretation supports the Planning Coordinator's supervisory role in directing the coordination of the planning process, including the specification of any methodologies to be used by Transmission Planners in its area. Such authority is also implied by a common sense reading of the standard itself. Assume that the standard was written with the understanding that the Planning Coordinator *did not* have this authority. Each of its Transmission Planners would be free to make and adopt its own methods, and the Planning Coordinator's assessment as well as each Transmission Planner's assessment would be invalid on its face due solely to the lack of coordination. (Remember that M1 and M2 apply to both the Planning Coordinator *and* its Transmission Planners.) As we stated in the interpretation "As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters."		
3	BC Hydro and Power Authority	Integrated system planning roles and responsibilities in British Columbia (BC) are under review.
Response: No response is required.		
3	Consumers Energy	While the intent seems clear the following sentence from the last paragraph is not: "TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required." (What does the "are required" refer to, "inclusion" or "outages"?)
Response: We thank you for your comment. There appears to be a typographical error it the cited first sentence, and we will modify the first sentence by inserting the phrase "performed is" as shown: "TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are <u>performed is</u> required.		
3	Manitoba Hydro	Manitoba Hydro agrees with the interpretation outlined in TPL-003-0 R1.3.12; however, Manitoba Hydro does not agree with the interpretation of TPL-002-0 and TPL-003-0 R1.3.2. The standard puts the onus of defining critical system conditions on the PA/TP. The revised interpretation creates confusion as it is now unclear as to whether the PA/TP or RE as Compliance monitor is to determine the critical system conditions.
Response: We thank you for your comments. We respectfully disagree with your conclusion regarding our interpretation of R1.3.2. The Planning Coordinator has the authority to specify "critical system conditions." As we stated in the interpretation "As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters."		
3	MidAmerican Energy Co.	We believe the critical conditions for the Transmission Planner planning should be determined

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		by the Transmission Planner while we agree that the Planning Coordinator should determine the critical conditions for the Planning Coordinator's area.
Response: We thank you for your comment, which addresses R1.3.2. However, the comment is illogical unless the Planning Coordinator and the Transmission Planner are one and the same.		
3	Orlando Utilities Commission	AMEREN: 1.3.2: Recommend Affirmative vote. AMEREN: 1.3.12: Recommend Negative Vote. Comment: The revised interpretation left out the discretion on behalf of the TP or PC. The discretion of the TP and/or PC should remain part of the interpretation since it would be impractical to perform long term studies with every possible planned outage included. The discretion part allows the TP and/or the PC to include those outages that are of significant duration and not study those that are of short duration. There are other standards and practices under which outages are reviewed so that the system is operated reliability and mandated that additional study is done under the TPL standard for even a short outage is impractical and provides no reliability gain. To address our concern we recommend replacing the first sentence; “TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required.” With the first sentence from the first interpretation: “TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed are within the discretion of the Planning Authority/Transmission Planner.” The second sentence is excellent and we agree that it addressed the question asked.
Response: We thank you for your comment. We respectfully disagree that the consideration of planned outages is somehow discretionary by the Planning Coordinator or Transmission Planner. R.1.3.12 is a requirement, and as such, cannot be optional or discretionary. However, the requirement does not specify a method for the modeling of planned outages; such modeling methods are within the discretion of the Planning Authority [Planning Coordinator] to specify, and those methods should be consistently used by all its Transmission Planners.		
3	Salt River Project	R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity. Although SRP agrees that the Planning Authority (PA) shall have the discretion in choosing the appropriate conditions to study for their system(s), we disagree with the language as stated. There is no definition of how or what a PA shall do in the “methodology.” Methodology is not described in any Standard to this point. Therefore, how could compliance be measured? Methodology needs to be described or enumerated to be applied in Standards and for compliance. R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed. SRP agrees with the revised interpretation of TPL-002-0 and TPL-003-0 R1.3.12 as developed by the NERC Planning Committee on March 12, 2008.
Response: We thank you for your comment. We agree that a methodology for defining “critical system conditions” is not part of TPL-002		

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and TPL-003. The reference to "methodology" in the interpretation comes from the Functional Model language we cited, and that citation states that the Planning Coordinator "provides…Transmission Planners …methodologies and tools for the simulation of the transmission system." We further state that a "PC's selection of "critical system conditions" fall within the purview of "methodology." We use this citation to establish the Planning Coordinators authority for specifying "critical system conditions" which it determines are appropriate. The standards do not require a methodology and our interpretation does not require one.		
3	Southern Indiana Gas and Electric Co.	The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008: TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL- 002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the NERC Glossary of Terms Used in Standards. Vectren requests that consideration be given to change the verbiage; "include any necessary system adjustments" to include the word "reasonable" or some other similar word to limit the system adjustments. The suggested verbiage would then read "include any reasonable and necessary system adjustments". Vectren does not believe that the word "necessary" provides enough limitation to the adjustments that should be considered. If the system adjustment necessary to eliminate an overload caused by the planned outage combined with contingency assessment requires an unreasonable amount of generation redispatch or the dropping of firm load, there should be some ability for the Transmission Planner or the Planning Authority to make the determination that the adjustment is unreasonable and another remedy for the overload must be explored. Your consideration in this matter is appreciated.
Response: We thank you for your comment, which addresses R1.3.12. We do not believe that the addition of the word "reasonable" has additional interpretative value. The language posed by Southern Indiana Gas and Electric Co. is an attempt to remove load shedding as a possible "necessary system adjustment" prior to modeling a contingency assessment. We do not believe that the word "reasonable" will accomplish this goal, nor do we believe it is required. It is not required because we do not believe that load shedding would ever be considered a "necessary system adjustments which might be required to accommodate planned outages" as our interpretation states. In support of this conclusion, consider TPL-002. It does not permit the loss of demand except as noted in footnote "b." If a Planning Coordinator or Transmission Planner attempted to "pass" TPL-002 by *a priori* load shedding under the guise of a "necessary system adjustment" for a planned outage, they would have shed load in order to comply with a standard that does not permit load shedding, and we would expect the RE reviewing the assessment to find it invalid.		
3	Wisconsin Electric Power Marketing	We agree with the principle that the TP and TO needs to apply discretion to the contingent topology of the cases, but the actual wording in the standard does not seem to allow that discretion.

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Response: We thank you for your comment. We believe that it is addressing our interpretation of R1.3.12, but are unsure. We do not state that R1.3.12 is discretionary in our revised interpretation.		
4	Wisconsin Energy Corp.	We agree with the principle that the TP and TO needs to apply discretion to the contingent topology of the cases, but the actual wording in the standard does not seem to allow that discretion.
Response: We thank you for your comment. We believe that it is addressing our interpretation of R1.3.12, but are unsure. We do not state that R1.3.12 is discretionary in our revised interpretation.		
5	City of Tallahassee	While I agree with the Revised Interpretation, I have to vote no because of the text before it that would gain teeth if this were approved. “As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner.” The Standard does NOT state “that the Compliance Monitor (or RE) has to approve the ‘valid assessment”. The Assessment is up to the PC and TP. The text quoted above IMPLIES that the RE must approve the assessment. If that is the case, put in a standard change request. The RE can only check that the assessment exists. If they don’t like it, they can make a recommendation to change it, but it is not a compliance issue. IF the text was true, I should be able to submit my assessment for evaluation without risking a compliance violation for asking for the approval that you imply is needed. The Compliance folks at the RE have told me that if we ask a question and it is a violation, we would get investigated and reported. I have to have an assessment (or procedure) and follow it, but the RE doesn’t have to like it. If they don’t like it, they can make a SUGGESTION, but not find non-compliance.
Response: We thank you for your comment. With regards to R1.3.2, we disagree with your statement that the Compliance Monitor does not determine whether an assessment is “valid.” That is what its auditing of compliance requires. However, an RE’s obligation to determine whether an assessment is “valid” does not allow the RE to micromanage the assessments it reviews. For example, it cannot reject a corrective plan (e.g., the proposed construction of new facilities) because it believes another plan would be more cost effective. If the proposed corrective plan fulfills the standard’s requirements, it is not reviewable by the RE.		
5	City Water, Light & Power of Springfield	The interpretation states that "The selection of a credible generation dispatch for the modeling under critical system conditions is within the direction of the Planning Authority." Under the proposed Version 4 of the NERC Functional Model, there is no longer a Planning Authority/Planning Coordinator. This interpretation means nothing if there is no longer a Planning Authority/Planning Coordinator.
Response: We thank you for your comment. Version 4 of the Functional Model is not approved; in fact, it was just posted for public comment, and the results have not yet been released.		
5	Dominion Energy	The original interpretation put the responsibility of determining the critical system condition on

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		both the Planning Authority and Transmission Planner. Local Transmission Owners should retain the ability to have internal planning criteria for their local systems and are not precluded from doing so by the Functional Model, Version 3. This interpretation appears to preclude that and would remove the Transmission Planner as a responsible party in determining this critical system condition.
Response: We thank you for your comments. Our interpretation does not preclude a Transmission Planner from adopting stricter planning criteria than required by a standard. That is any Transmission Planner's prerogative. However, with regard to the assumptions for critical system conditions within a Planning Coordinator's area *associated with compliance with a NERC standard*, those are formulated by the Planning Coordinator.		
5	Manitoba Hydro	Manitoba Hydro agrees with the interpretation outlined in TPL-003-0 R1.3.12; however, Manitoba Hydro does not agree with the interpretation of TPL-002-0 and TPL-003-0 R1.3.2. The standard puts the onus of defining critical system conditions on the PA/TP. The revised interpretation creates confusion as it is now unclear as to whether the PA/TP or RE as Compliance monitor is to determine the critical system conditions.
Response: We thank you for your comments. We respectfully disagree with your conclusion regarding our interpretation of R1.3.2. The Planning Coordinator has the authority to specify "critical system conditions." As we stated in the interpretation "As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters."		
5	Salt River Project	R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity. Although SRP agrees that the Planning Authority (PA) shall have the discretion in choosing the appropriate conditions to study for their system(s), we disagree with the language as stated. There is no definition of how or what a PA shall do in the "methodology". Methodology is not described in any Standard to this point. Therefore, how could compliance be measured? Methodology needs to be described or enumerated to be applied in Standards and for compliance. R.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed. SRP agrees with the revised interpretation of TPL-002-0 and TPL-003-0 R1.3.12 as developed by the NERC Planning Committee on March 12, 2008.
Response: We thank you for your comment. What Salt River Project is seeking is a greater specificity in R1.3.2 and R1.3.12. However, such additional specificity cannot be provided by an interpretation.		
5	Southern California Edison Co.	Interpretation of R1.3.2 addresses the question raised by Ameren. Interpretation R1.3.12 does not fully address question posed by Ameren which led to some discussion during our internal review process.

Segment	Organization	Comment
Response: We cannot respond to this comment since no specific reason was given.		
5	Wisconsin Electric Power Co.	We agree with the principle that the TP and TO needs to apply discretion to the contingent topology of the cases, but the actual wording in the standard does not seem to allow that discretion.
Response: We thank you for your comment. We believe that it is addressing our interpretation of R1.3.12, but are unsure. We do not state that R1.3.12 is discretionary in our revised interpretation.		
6	Dominion Resources, Inc.	We do not support the removal of Transmission Planner.
Response: We cannot respond to the comment because we do not understand what part of the interpretation the comment references. In addition, it does not provide a reason.		
6	Manitoba Hydro	Manitoba Hydro agrees with the interpretation outlined in TPL-003-0 R1.3.12; however, Manitoba Hydro does not agree with the interpretation of TPL-002-0 and TPL-003-0 R1.3.2. The standard puts the onus of defining critical system conditions on the PA/TP. The revised interpretation creates confusion as it is now unclear as to whether the PA/TP or RE as Compliance monitor is to determine the critical system conditions.
Response: We thank you for your comments. We respectfully disagree with your conclusion regarding our interpretation of R1.3.2. The Planning Coordinator has the authority to specify “critical system conditions.” As we stated in the interpretation “As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters."		
6	Southern Indiana Gas and Electric Co.	The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008: TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL- 002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the NERC Glossary of Terms Used in Standards. Vectren requests that consideration be given to change the verbiage; "include any necessary system adjustments" to include the word "reasonable" or some other similar word to limit the system adjustments. The suggested verbiage would then read "include any reasonable and necessary system adjustments". Vectren does not believe that the word "necessary" provides enough limitation to the adjustments that should be considered. If the system adjustment necessary to eliminate an overload caused by the planned outage combined with contingency assessment requires an unreasonable amount of generation redispatch or the dropping of firm load, there should be some ability for the Transmission Planner or the Planning Authority to make the determination that the adjustment

Segment	Organization	Comment
		is unreasonable and another remedy for the overload must be explored. Your consideration in this matter is appreciated.
Response: We thank you for your comment, which addresses R1.3.12. We do not believe that the addition of the word "reasonable" has additional interpretative value. The language posed by Southern Indiana Gas and Electric Co. is an attempt to remove load shedding as a possible "necessary system adjustment" prior to modeling a contingency assessment. We do not believe that the word "reasonable" will accomplish this goal, nor do we believe it is required. It is not required because we do not believe that load shedding would ever be considered a "necessary system adjustments which might be required to accommodate planned outages" as our interpretation states. In support of this conclusion, consider TPL-002. It does not permit the loss of demand except as noted in footnote "b." If a Planning Coordinator or Transmission Planner attempted to "pass" TPL-002 by *a priori* load shedding under the guise of a "necessary system adjustment" for a planned outage, it would have shed load in order to comply with a standard that does not permit load shedding, and we would expect the RE reviewing the assessment to reject it.		
9	Commonwealth of Massachusetts Department of Public Utilities	The interpretation says "Planning Authority/Transmission Provider". The "and/or" can be read as either an "and" or an "or'. The difference is that the entities have to either come to a mutual agreement or can make independent assessments. Although it is thought that it will generally be a mutual decision, we think this is an issue that the two entities can work out how they address and doesn't need to be dictated by the standard. Therefore we think the interpretation should have the "and/or" replaced with an "or".
Response: We thank you for your comment, but it appears that your comment refers to the original interpretation of R1.3.2, not our revised interpretation.		

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standards

Ballot Results	
Ballot Name:	Request for Interpretation - TPL-002 and TPL-003 - Ameren_in
Ballot Period:	4/25/2008 - 5/7/2008
Ballot Type:	Initial
Total # Votes:	171
Total Ballot Pool:	207
Quorum:	**82.61 % The Quorum has been reached**
Weighted Segment Vote:	80.73 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	64	1	36	0.72	14	0.28	3	11
2 - Segment 2.	9	0.6	5	0.5	1	0.1	1	2
3 - Segment 3.	50	1	32	0.762	10	0.238	2	6
4 - Segment 4.	8	0.7	6	0.6	1	0.1	1	0
5 - Segment 5.	35	1	19	0.76	6	0.24	3	7
6 - Segment 6.	23	1	12	0.706	5	0.294	0	6
7 - Segment 7.	1	0	0	0	0	0	0	1
8 - Segment 8.	2	0.1	1	0.1	0	0	0	1
9 - Segment 9.	7	0.5	5	0.5	0	0	0	2
10 - Segment 10.	8	0.6	6	0.6	0	0	2	0
Totals	**207**	**6.5**	**122**	**5.248**	**37**	**1.252**	**12**	**36**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services Company	Kirit S. Shah	Negative	View
1	American Transmission Company, LLC	Jason Shaver	Negative	View
1	Arizona Public Service Co.	Cary B. Deise	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Avista Corp.	Scott Kinney	Abstain	
1	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	CenterPoint Energy	Paul Rocha	Affirmative	
1	City of Tallahassee	Gary S. Brinkworth	Affirmative	

1	City Utilities of Springfield, Missouri	Jeff Knottek		
1	Consolidated Edison Co. of New York	Edwin E. Thompson PE	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	William L. Thompson	Negative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba		
1	Entergy Corporation	George R. Bartlett	Negative	View
1	Exelon Energy	John J. Blazekovich	Abstain	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	C. Martin Mennes	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Negative	View
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	ITC Transmission	Brian F. Thumm		
1	JEA	Ted E. Hobson		
1	Kansas City Power & Light Co.	Jim Useldinger	Affirmative	
1	Keyspan LIPA	Richard J. Bolbrock		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Lower Colorado River Authority	Martyn Turner		
1	Manitoba Hydro	Michelle Rheault	Negative	View
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	Municipal Electric Authority of Georgia	Jerry J Tang	Affirmative	
1	National Grid	Michael J Ranalli	Affirmative	
1	Nebraska Public Power District	Richard L. Koch		
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Affirmative	
1	New York Power Authority	Ralph Rufrano	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Joseph Dobes	Affirmative	
1	Omaha Public Power District	lorees Tadros	Negative	View
1	Oncor Electric Delivery	Charles W. Jenkins	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	View
1	PacifiCorp	Robert Williams		
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Sacramento Municipal Utility District	Dilip Mahendra	Negative	View
1	Salt River Project	Robert Kondziolka	Negative	View
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson		
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Christopher M. Turner	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Indiana Gas and Electric Co.	Michael Chambliss	Negative	View
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Tucson Electric Power Co.	Ronald P. Belval	Negative	View

1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Robert Temple	Affirmative	
1	Xcel Energy, Inc.	Gregory L. Pieper	Affirmative	
2	Alberta Electric System Operator	Anita Lee		
2	British Columbia Transmission Corporation	Phil Park	Negative	View
2	California ISO	David Hawkins	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Roy D. McCoy	Abstain	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	View
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
3	Alabama Power Company	Robin Hurst	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services Company	Mark Peters	Negative	View
3	American Electric Power	Raj Rana	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	View
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Tallahassee	Rusty S. Foster	Negative	
3	City Public Service of San Antonio	Edwin Les Barrow	Affirmative	
3	Commonwealth Edison Co.	Stephen Lesniak		
3	Consumers Energy	David A. Lapinski	Affirmative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik		
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	Entergy Services, Inc.	Matt Wolf	Negative	
3	Farmington Electric Utility System	Alan Glazner	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	
3	Florida Municipal Power Agency	Michael Alexander	Affirmative	
3	Florida Power & Light Co.	W.R. Schoneck	Abstain	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker		
3	Kissimmee Utility Authority	Gregory David Woessner		
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Ronald Dacombe	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Christopher Lawrence de Graffenried	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Negative	View
3	PECO Energy an Exelon Co.	John J. McCawley		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	

3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Salt River Project	John T. Underhill	Negative	View
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern Indiana Gas and Electric Co.	Fred Frederick	Negative	View
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Cynthia Herron		
3	Wisconsin Electric Power Marketing	James R. Keller	Negative	View
3	Wisconsin Public Service Corp.	James A. Maenner	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	American Municipal Power - Ohio	Chris Norton	Abstain	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
4	WPS Resources Corp.	Christopher Plante	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tallahassee	Alan Gale	Negative	View
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Negative	View
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Affirmative	
5	Conectiv Energy Supply, Inc.	Richard K. Douglass	Affirmative	
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Energy	Harold W. Adams	Negative	View
5	Dynegy	Greg Mason	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker		
5	Entergy Corporation	Stanley M Jaskot		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	Douglas Keegan	Affirmative	
5	Florida Power & Light Co.	Robert A. Birch	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	
5	Manitoba Hydro	Mark Aikens	Negative	View
5	New York Power Authority	Richard J. Ardolino		
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	Reliant Energy Services	Thomas J. Bradish	Affirmative	
5	Salt River Project	Glen Reeves	Negative	View
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	South Carolina Electric & Gas Co.	Richard Jones		
5	Southeastern Power Administration	Douglas Spencer	Abstain	
5	Southern California Edison Co.	David Schiada	Affirmative	View
5	Southern Company Services, Inc.	Roger D. Green	Affirmative	
5	Southern Indiana Gas and Electric Co.	Mark Rose		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View

5	Xcel Energy, Inc.	Stephen J. Beuning		
6	AEP Marketing	Edward P. Cox	Affirmative	
6	AEP Service Corp.	Dana E. Horton		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Dominion Resources, Inc.	Louis S Slade	Negative	View
6	Entergy Services, Inc.	William Franklin	Negative	
6	Exelon Power Team	Pulin Shah		
6	First Energy Solutions	Alfred G. Roth		
6	Florida Municipal Power Agency	Robert C. Williams		
6	Great River Energy	Donna Stephenson		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PP&L, Inc.	Thomas Hyzinski	Affirmative	
6	Progress Energy Carolinas	James Eckelkamp	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Salt River Project	Mike Hummel	Negative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Southern Company Generation and Energy Marketing	J. Roman Carter		
6	Southern Indiana Gas and Electric Co.	Brad Lisembee	Negative	View
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Eastman Chemical Company	Lloyd Webb		
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Other	Michehl R. Gent		
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	View
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Public Service Commission	James T. Gallagher		
9	North Carolina Utilities Commission	Kimberly J. Jones	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Affirmative	
9	Wyoming Public Service Commission	Steve Oxley		
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Midwest Reliability Organization	Larry Brusseau	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Edward A. Schwerdt	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith	Affirmative	
10	SERC Reliability Corporation	Carter Edge	Abstain	
10	Southwest Power Pool	Charles H. Yeung	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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Standards Announcement

Initial Ballot Results for Two Interpretations
April 25–May 5, 2008

Now available at: https://standards.nerc.net/Ballots.aspx

Initial Ballot Results for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren

The initial ballot for the revised Interpretation (for Ameren) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements, was conducted from April 25–May 5, 2008.

The ballot achieved a quorum; however, there were some negative ballots with comments, initiating the need to review the comments and determine whether the interpretation needs modification before proceeding to a re-circulation ballot. The drafting team will be reviewing comments submitted with the ballot and preparing its consideration of those comments. (Detailed Ballot Results)

Quorum:	82.61 %
Approval:	80.73 %

Initial Ballot Results for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO

The initial ballot for the revised Interpretation (for MISO) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements, was conducted from April 25–May 5, 2008.

The ballot achieved a quorum; however, there were some negative ballots with comments, initiating the need to review the comments and determine whether the interpretation needs modification before proceeding to a re-circulation ballot. The drafting team will be reviewing comments submitted with the ballot and preparing its consideration of those comments. (Detailed Ballot Results)

Quorum:	83.01 %
Approval:	79.89 %

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

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Interpretation of TPL-002-0 Requirement R1.3.2 and Requirement R1.3.12 and the Identical Requirements (R1.3.2 and R1.3.12) in TPL-003-0 for Ameren

Request for Interpretation of TPL-002 and TPL-003 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

From TPL-002-0 and -003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002 and TPL-003 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions. The selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority/Transmission Planner.

The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

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Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

From TPL-002-0 and -003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed are within the discretion of the Planning Authority/Transmission Planner.

The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interpretation of TPL-002-0 Requirement R1.3.2 and Requirement R1.3.12 and the Identical Requirements (R1.3.2 and R1.3.12) in TPL-003-0 for Ameren

Request for Interpretation of TPL-002 and TPL-003 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

From TPL-002-0 and -003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002 and TPL-003 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions. The selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority/Transmission Planner.

The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

From TPL-002-0 and -003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed are within the discretion of the Planning Authority/Transmission Planner.

The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Standards Announcement

Recirculation Ballot Windows Open for Two Interpretations

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Recirculation Ballot Window for Revised Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren is Open

The recirculation ballot for the revised interpretation (for Ameren) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements, is open and will remain open until 8 p.m. (EST) on Monday, July 7, 2008.

Note that there was a typographical error in the version of the interpretation that was posted for initial ballot. The two words, "performed is" have been added to the following sentence:

> TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is required.

The Standards Committee encourages all members of the Ballot Pool to review the consideration of comments submitted with the initial ballots. The drafting team corrected a typographical error in the last paragraph of the interpretation following the initial ballot and has posted both a clean and a redline version of the corrected interpretation. Members of the ballot pool may:

- Reconsider and change their vote from the first ballot.
- Vote in the second ballot even if they did not vote on the first ballot.
- Take no action if they do not want to change their original vote.

In the recirculation ballot, votes are counted by exception only — if a Ballot Pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot.

Recirculation Ballot Window for Revised Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO is Open

The recirculation ballot for the revised interpretation (for MISO) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements, is open and will remain open until 8 p.m. (EST) on Monday, July 7, 2008.

The Standards Committee encourages all members of the Ballot Pool to review the consideration of comments submitted with the initial ballots. The drafting team corrected a typographical error in the last paragraph of the interpretation following the initial ballot and has posted both a clean and a redline version of the corrected interpretation. Members of the ballot pool may:

- Reconsider and change their vote from the first ballot.

- Vote in the second ballot even if they did not vote on the first ballot.
- Take no action if they do not want to change their original vote.

In the recirculation ballot, votes are counted by exception only — if a Ballot Pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot.

Standards Development Process

The *Reliability Standards Development Procedure Manual* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Maureen Long,
Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

Ameren Services

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July 25, 2007

Maureen E. Long
Standards Process Manager
North American Electric Reliability Council
Princeton Forrestal Village
116-390 Village Boulevard
Princeton, New Jersey 08540-5721

Ameren

RE: Request for Interpretation of NERC Standards TPL-002-0 and TPL-003-0

Dear Ms. Long:

In accordance with the NERC Reliability Standards Development Procedure, I am requesting a formal interpretation of two sub-requirements which are common to NERC standards TPL-002-0 and TPL-003-0. These sub-requirements are included in R1.3 of both standards and pertain to the simulation testing to assess system performance for Category B and Category C contingencies as defined in Table 1 of the standards. The specific sub-requirements for which clarification is requested are:

> R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
>
> R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.3.2
Questions requiring interpretation:

How should the phrase "critical system conditions" be interpreted? Does compliance with R1.3.2 require multiple contingent generation unit outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be operated in accordance with the contingency definitions included in Table 1 of the TPL standards?

The following are two possible but conflicting interpretations.

1. The phrase "critical system conditions" defines a set of known or planned system conditions pertaining to load, generation dispatch, and firm transmission service reservations such as might describe summer peak, winter peak or some other assumed system conditions. Alternate generation dispatch scenarios may be evaluated. However, it is not the intent of the requirements that these alternate dispatch scenarios must include multiple contingent generation unit outages as might typically be considered to satisfy a resource adequacy planning criterion. Further, it is **not** the intent of the TPL standards that compliance requires the system to be planned to operate with multiple contingent generation unit outages as might be defined by a resource adequacy criterion **and** meet the conditions associated with contingent outages in Table 1.

2. The phrase "critical system condition" includes a variety of possible dispatch patterns including probabilistic based dispatch representative of generation deficiency scenarios with multiple contingent outages, as defined by the Transmission Planner or Planning Authority. Compliance with the TPL standard requires the application of the transmission contingency conditions in Table 1 **in addition** to these multiple contingent generation outages.

The material impacts of misinterpretation of this sub-requirement are:

- Interpretation of this sub-requirement is necessary to establish appropriate cost allocation of proposed system expansion in the Midwest ISO footprint, both within the Midwest ISO and between the Midwest ISO and PJM member companies.
- Interpretation 2 will lead to inconsistent application/interpretation of the contingency definitions included in Table 1, since the number of unit outages can vary based on the size and generation mix of each Transmission Planner's area of responsibility. As such it will be difficult to determine which contingent generation outages are part of the assumptions related to critical conditions and which are part of the contingency definitions in Table 1.
- Interpretation 2 will make compliance assessment more difficult as it relies on the judgment of the Transmission Planner or Transmission Coordinator to define which and how many contingent generator unit outages to include in the base case.
- Interpretation 2 can create a de facto transfer capability requirement.
- Interpretation 2 could dramatically increase the hurdles for the connection of new generation to system.

R.1.3.12
Questions requiring interpretation:

How should the inclusion of planned outages be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C? Does compliance with R1.3.12 require that the system be planned to operate during those conditions associated with planned outages consistent with the performance requirements described in Table 1 **plus** any unidentified planned outage?

The following are two possible but conflicting interpretations of this sub-requirement:

1. Any bulk electric equipment for which there is a known outage planned for a given point in time should be modeled as out of service in any base case model associated with the planned outage period. Such outages should not be restored prior to assessment of the applicable outage category specified by the standard. The ability to plan outages would be **accommodated** in the planning process by increasing the contingency definitions in Category B and/or Category C by one event in those studies of system conditions for which planned outages are typically performed. Standards compliance with Category B and Category C requirements would accommodate the potential planned outages through switching or redispatch so as to mitigate any limit or ratings violations.

2. In addition to known planned outages, the system shall be planned to include potential planned outages such that the system can be operated under those conditions for which planned outages are typically performed. As such, the contingency definitions associated with Category B and C events listed in Table 1 should be increased by one additional event in studies of system conditions for which planned outages are typically performed. Compliance with Category B and C events, including the addition of any potential planned outage, would be unchanged from the requirements in Table 1. Compliance with the requirement does not permit switching, redispatch or other mitigation measures to address any limit or ratings violations created by a potential planned outage for Category B events.

It should be noted that the pre Version 0 standard I.A.S2 stated that: "*...systems must be capable of meeting Category B requirements while **accommodating** the planned ... outage of any bulk electric equipment... at those demand levels for which planned... outages are performed.*" *(emphasis added)* The I.A.S2 language regarding the ***accommodation*** of planned outages was not explicitly

captured in R.1.3.12. As such there is confusion as to how to address the issue of planned outages in the application of the TPL standards.

The material impacts of misinterpretation of this sub-requirement are:

- Interpretation of this sub-requirement is necessary to establish appropriate cost allocation of proposed system expansion in the Midwest ISO footprint, both within the Midwest ISO and between the Midwest ISO and PJM member companies.
- Interpretation 2 implies that the system should be planned such that any maintenance outage can be scheduled at demand levels for which planned outages are typically performed without the need to consider mitigation plans, alternate generation dispatch, or other outage coordination efforts which may facilitate maintenance outages.
- Interpretation 2 will result in confusion regarding appropriate contingency levels and mitigation options to be included under those conditions during which planned outages are typically planned.
- Interpretation 2 would increase the hurdles for the connection of new generation to the system by virtue of an increase in the contingency levels used in connection studies of off-peak conditions.

Thank your for your prompt consideration of these standards interpretation questions.

Sincerely,

Ed Pfeiffer
Manager, Electric Planning

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standards

Ballot Results	
Ballot Name:	Request for Interpretation - TPL-002 and TPL-003 - Ameren_rc
Ballot Period:	6/27/2008 - 7/7/2008
Ballot Type:	recirculation
Total # Votes:	173
Total Ballot Pool:	207
Quorum:	**83.57 % The Quorum has been reached**
Weighted Segment Vote:	79.13 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	64	1	38	0.745	13	0.255	3	10
2 - Segment 2.	9	0.6	5	0.5	1	0.1	1	2
3 - Segment 3.	50	1	32	0.762	10	0.238	2	6
4 - Segment 4.	8	0.7	5	0.5	2	0.2	1	0
5 - Segment 5.	35	1	19	0.731	7	0.269	3	6
6 - Segment 6.	23	1	12	0.706	5	0.294	0	6
7 - Segment 7.	1	0	0	0	0	0	0	1
8 - Segment 8.	2	0.1	1	0.1	0	0	0	1
9 - Segment 9.	7	0.5	5	0.5	0	0	0	2
10 - Segment 10.	8	0.6	6	0.6	0	0	2	0
Totals	**207**	**6.5**	**123**	**5.144**	**38**	**1.356**	**12**	**34**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services Company	Kirit S. Shah	Negative	View
1	American Transmission Company, LLC	Jason Shaver	Negative	View
1	Arizona Public Service Co.	Cary B. Deise	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Avista Corp.	Scott Kinney	Abstain	
1	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	CenterPoint Energy	Paul Rocha	Affirmative	
1	City of Tallahassee	Gary S. Brinkworth	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek		
1	Consolidated Edison Co. of New York	Edwin E. Thompson PE	Affirmative	

1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	William L. Thompson	Negative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba		
1	Entergy Corporation	George R. Bartlett	Negative	View
1	Exelon Energy	John J. Blazekovich	Abstain	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	C. Martin Mennes	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Negative	View
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	ITC Transmission	Brian F. Thumm		
1	JEA	Ted E. Hobson		
1	Kansas City Power & Light Co.	Jim Useldinger	Affirmative	
1	Keyspan LIPA	Richard J. Bolbrock		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Lower Colorado River Authority	Martyn Turner		
1	Manitoba Hydro	Michelle Rheault	Negative	View
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	Municipal Electric Authority of Georgia	Jerry J Tang	Affirmative	
1	National Grid	Michael J Ranalli	Affirmative	
1	Nebraska Public Power District	Richard L. Koch		
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Affirmative	
1	New York Power Authority	Ralph Rufrano	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Joseph Dobes	Affirmative	
1	Omaha Public Power District	lorees Tadros	Affirmative	
1	Oncor Electric Delivery	Charles W. Jenkins	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	View
1	PacifiCorp	Robert Williams	Affirmative	
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Sacramento Municipal Utility District	Dilip Mahendra	Negative	View
1	Salt River Project	Robert Kondziolka	Negative	View
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson		
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Christopher M. Turner	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Indiana Gas and Electric Co.	Michael Chambliss	Negative	View
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Tucson Electric Power Co.	Ronald P. Belval	Negative	View
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Robert Temple	Affirmative	
1	Xcel Energy, Inc.	Gregory L. Pieper	Affirmative	
2	Alberta Electric System Operator	Anita Lee		
2	British Columbia Transmission Corporation	Phil Park	Negative	View
2	California ISO	David Hawkins	Affirmative	
	Electric Reliability Council of Texas,			

2	Inc.	Roy D. McCoy	Abstain	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	View
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
3	Alabama Power Company	Robin Hurst	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services Company	Mark Peters	Negative	View
3	American Electric Power	Raj Rana	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	View
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Tallahassee	Rusty S. Foster	Negative	
3	City Public Service of San Antonio	Edwin Les Barrow	Affirmative	
3	Commonwealth Edison Co.	Stephen Lesniak		
3	Consumers Energy	David A. Lapinski	Affirmative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik		
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	Entergy Services, Inc.	Matt Wolf	Negative	
3	Farmington Electric Utility System	Alan Glazner	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	
3	Florida Municipal Power Agency	Michael Alexander	Affirmative	
3	Florida Power & Light Co.	W.R. Schoneck	Abstain	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker		
3	Kissimmee Utility Authority	Gregory David Woessner		
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Ronald Dacombe	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Christopher Lawrence de Graffenried	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Negative	View
3	PECO Energy an Exelon Co.	John J. McCawley		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Salt River Project	John T. Underhill	Negative	View
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern Indiana Gas and Electric Co.	Fred Frederick	Negative	View
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Cynthia Herron		
3	Wisconsin Electric Power Marketing	James R. Keller	Negative	View
3	Wisconsin Public Service Corp.	James A. Maenner	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	

4	American Municipal Power - Ohio	Chris Norton	Abstain	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
4	WPS Resources Corp.	Christopher Plante	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tallahassee	Alan Gale	Negative	View
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Negative	View
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Affirmative	
5	Conectiv Energy Supply, Inc.	Richard K. Douglass	Affirmative	
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Energy	Harold W. Adams	Negative	View
5	Dynegy	Greg Mason	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker		
5	Entergy Corporation	Stanley M Jaskot	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	Douglas Keegan	Affirmative	
5	Florida Power & Light Co.	Robert A. Birch	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	
5	Manitoba Hydro	Mark Aikens	Negative	View
5	New York Power Authority	Richard J. Ardolino		
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	Reliant Energy Services	Thomas J. Bradish	Affirmative	
5	Salt River Project	Glen Reeves	Negative	View
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	South Carolina Electric & Gas Co.	Richard Jones		
5	Southeastern Power Administration	Douglas Spencer	Abstain	
5	Southern California Edison Co.	David Schiada	Affirmative	View
5	Southern Company Services, Inc.	Roger D. Green	Affirmative	
5	Southern Indiana Gas and Electric Co.	Mark Rose		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Xcel Energy, Inc.	Stephen J. Beuning		
6	AEP Marketing	Edward P. Cox	Affirmative	
6	AEP Service Corp.	Dana E. Horton		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Dominion Resources, Inc.	Louis S Slade	Negative	View
6	Entergy Services, Inc.	William Franklin	Negative	
6	Exelon Power Team	Pulin Shah		
6	First Energy Solutions	Alfred G. Roth		
6	Florida Municipal Power Agency	Robert C. Williams		
6	Great River Energy	Donna Stephenson		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PP&L, Inc.	Thomas Hyzinski	Affirmative	
6	Progress Energy Carolinas	James Eckelkamp	Affirmative	

6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Salt River Project	Mike Hummel	Negative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Southern Company Generation and Energy Marketing	J. Roman Carter		
6	Southern Indiana Gas and Electric Co.	Brad Lisembee	Negative	View
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Eastman Chemical Company	Lloyd Webb		
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Other	Michehl R. Gent		
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	View
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Public Service Commission	James T. Gallagher		
9	North Carolina Utilities Commission	Kimberly J. Jones	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Affirmative	
9	Wyoming Public Service Commission	Steve Oxley		
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Midwest Reliability Organization	Larry Brusseau	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Edward A. Schwerdt	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Abstain	
10	Southwest Power Pool	Charles H. Yeung	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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Standards Announcement

Final Ballot Results for Two Interpretations (Project 2007-24 and Project 2007-26)

Now available at: https://standards.nerc.net/Ballots.aspx

Final Ballot Results for Project 2007-24 — Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren

The recirculation ballot for the revised Interpretation (for Ameren) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements was conducted from June 27–July 7, 2008 and the ballot was approved.

The Ballot Results standards Web page provides a link to the detailed results for this ballot.

Quorum: 83.57 %
Approval: 79.13 %

Approval requires both:

- A quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention; and
- A two-thirds majority of the weighted segment votes cast must be affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding abstentions and no responses.

Final Ballot Results for Project 2007-26 — Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO

The recirculation ballot for the revised Interpretation (for MISO) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements, was conducted from June 27–July 7, 2008 and the ballot was approved.

The Ballot Results standards Web page provides a link to the detailed results for this ballot.

Quorum: 83.98 %
Approval: 78.31 %

Approval requires both:

- A quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention; and
- A two-thirds majority of the weighted segment votes cast must be affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding abstentions and no responses.

Standards Development Process

The *Reliability Standards Development Procedure Manual* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Maureen Long,
Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

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Exhibit B-1

Formal interpretation submitted for approval

TPL-003-0 — System Performance Following Loss of a Two or More Bulk Electric System Elements (Category C), Requirements R1.3.2 and R1.3.12

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO. These requirements state:

> TPL-002-0:
>
> [To be valid, the Planning Authority and Transmission Planner assessments shall:]
>
> **R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
>
> **R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
>
> **R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

> From TPL-003-0:
>
> [To be valid, the Planning Authority and Transmission Planner assessments shall:]
>
> **R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
>
> **R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
>
> **R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

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Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Exhibit B-2

Affected Reliability Standard that includes the appended interpretation

TPL-003-0a — System Performance Following Loss of a Two or More Bulk Electric System Elements (Category C), Requirements R1.3.2 and R1.3.12

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-0a

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0_R1 and TPL-003-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item "e" on page 8.	Errata
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3 Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

> **M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Exhibit B-3

The complete development record of the formal interpretation – Midwest ISO

TPL-002-0 — System Performance Following Loss of a One Bulk Electric System Element (Category B), Requirements R1.3.2 and R1.3.12

Interpretation of TPL-002-0 Requirements R1.3.2 and Requirement R1.3.12 and the identical requirements (Requirements R1.3.2 and Requirement R1.3.12) in TPL-003-0 for MISO

Request for Interpretation received from MISO on August 9:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

R1.3.2	Cover critical system conditions and study years as deemed appropriate by the responsible entity.

The following interpretation of TPL-002-0 and TPL-003-0 R1.3.2 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002 and TPL-003 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions. The selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority/Transmission Planner.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 received from MISO on August 9:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

> *The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by

NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

R1.3.12	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

The interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on September 12, 2007

TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed are within the discretion of the Planning Authority/Transmission Planner.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Maureen E. Long
Standards Process Manager

November 5, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement:
Three Pre-ballot Windows and Ballot Pools for Interpretations
Open November 5, 2007

The Standards Committee (SC) announces the following standards actions:

Pre-ballot Window and Ballot Pool for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren Both Open November 5, 2007

Ameren submitted a Request for an Interpretation of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements.

The request asked if TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 require multiple contingent generating unit outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be operated in accordance with the contingency definitions included in Table 1. The request also asked if TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 require that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

The Interpretation clarifies that TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions and clarifies that the selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority and the Transmission Planner. The interpretation also states that TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is within the discretion of the Planning Authority and the Transmission Planner.

A new ballot pool to vote on this interpretation has been formed and will remain open up until 8 a.m. (EST) Tuesday, December 4, 2007. During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." The list server for this ballot pool is: bp_Interpret_TPL_Ameren_in@ner.com

The initial ballot for this interpretation will begin at 8 a.m. (EST) on Tuesday, December 4, 2007.

Pre-ballot Window and Ballot Pool for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO Both Open November 5, 2007

MISO submitted a Request for an Interpretation of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements.

The request asked if TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asked if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios.

The request also asked if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

The Interpretation clarifies that TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions and clarifies that the selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority and the Transmission Planner. The interpretation also states that TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is within the discretion of the Planning Authority and the Transmission Planner.

A new ballot pool to vote on this interpretation has been formed and will remain open up until 8 a.m. (EST) Tuesday, December 4, 2007. During the pre-ballot window, members of the ballot pool may communicate with one another by using their “ballot pool list server.” The list server for this ballot pool is: bp_Interpret_TPL_MISO_in@nerc.com

The initial ballot for this interpretation will begin at 8 a.m. (EST) on Tuesday, December 4, 2007.

Pre-ballot Window and Ballot Pool for Interpretation of VAR-001-0 Requirement R4 for Dynegy Both Open November 5, 2007

Dynegy submitted a Request for an Interpretation of VAR-001-1 Requirement R4.

The request asked if the Transmission Operator is implicitly required to have a technical basis for specifying the voltage or reactive power schedule, asked if the voltage or reactive power schedule must be reasonable and practical for the Generator Operator to maintain, and asked what measure should be used to determine if the Transmission Operator has issued a technically based, reasonable and practical voltage or reactive power schedule.

The Interpretation clarifies that VAR-001-1 is only comprised of stated requirements and associated measures and compliance elements. Interpreting an 'implicit' requirement would effectively be adding a new requirement to the standard and needs to be achieved with a Standard Authorization Request (SAR) to modify the standard rather than through an Interpretation. There are no requirements in VAR-001-1 to issue a "technically based, reasonable and practical to maintain voltage or reactive power schedule and associated tolerance band."

A new ballot pool to vote on this interpretation has been formed and will remain open up until 8 a.m. (EST) Tuesday, December 4, 2007. During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." The list server for this ballot pool is: bp_Interpret_VAR_Dynegy_in@nerc.com

The initial ballot for this interpretation will begin at 8 a.m. (EST) on Tuesday, December 4, 2007.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Jeff Webb
Director Expansion Planning
Direct Dial: 317-249-5412
E-mail: jwebb@midwestiso.org

August 9, 2007

Maureen E. Long
Standards Process Manager
North American Electric Reliability Council
Princeton Forrestal Village
116-390 Village Boulevard
Princeton, New Jersey 0854-5721

Re: Request for Interpretation of NERC Standard TPL-002-0 and TPL-003-0

Ms. Long:

The Midwest Independent Transmission System Operator, Inc. (Midwest ISO) requests a formal interpretation of two sub requirements that are common to NERC standards TPL-002-0 and TPL-003-0, in accordance with the NERC Reliability Standards Development Procedure. The sub-requirements in question are Requirements R1.3.2 and R 1.3.12 of TPL-002 and TPL-003:

> R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
>
> R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

With respect to these two requirements, and more globally in the general application of the TPL standards, the Midwest ISO requests that NERC provide guidance with respect to the following application of the TPL standards:

1. The application of the TPL contingency requirements of Table 1 to dispatch patterns considered appropriate by the entity responsible for compliance is not a misapplication of the standard as it is within the bounds of discretion that the standard permits of the Transmission Planner and the Planning Authority as entities responsible for compliance, and;

2. The application of a standard in accordance with an existing interpretation based on the history and development of the standards is appropriate, notwithstanding future interpretations or revisions of the standard.

Specifically, with respect to the discretion that the TPL standard grants to the Transmission Planner and the Planning Authority, the Midwest ISO seeks NERC interpretation of following:

Q1.1: Do the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards?

Q1.2: If in the judgment of the entity responsible for compliance, a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch patterns?

With respect to the interpretation of R1.3.12 the Midwest ISO seeks NERC interpretation of the following:

Q2.1: Does the term "planned outages" mean only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

Q2.2: If it is intended to include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision? The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, redispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

Q2.3: If it is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard[1]?

Q2.4: If NERC provides a new interpretation of a standard, or an interpretation that is different than a prior clarification by NERC of a standard, or if NERC revises a standard, would the previous application of the standard according to the clarification, interpretation, or

[1] The NERC PSS provided responses to industry questions about the Planned Outage provision of Standard IA in September 2000, and the NERC office has these responses in their archives and has provided these to the Midwest ISO.

version of a standard in effect at the time it was applied be considered a proper application of the standard? Is the more recent interpretation deemed to be retroactive, invalidating previous planning studies?

Material Impact of Standards Interpretation

- Necessary transmission expansions may not be pursued depending on the interpretation of these issues. Regulatory authorities may not permit recovery of costs of appropriately planned transmission expansions if the NERC standards are construed to prescribe the precise system conditions that are appropriate to be planned for without permitting discretion in planning assumptions to be within the proper application of the NERC standards.

- The application of the NERC standards must permit that discretion be given to Transmission Planners and Planning Authorities to apply appropriate planning assumptions for their systems in development of planning models that the NERC standards are applied to. If the NERC standards are interpreted as specifically prescribing the generation patterns, including the number of generators off-line that it is prudent to plan for, it will make it difficult for Transmission Planners and Planning Authorities to plan their specific systems to perform reliably based on their experience with and the historical performance of their systems.

- If the interpretation, reinterpretation, or revision of a standard subsequent to the application of a standard to support the need for reliability upgrades renders the prior application of a standard inappropriate in NERC's view, this would create great uncertainty in the ability of a Transmission owner to recover costs for upgrades, and would result in reluctance by Transmission Owners to expand their systems based on present interpretations of the standards.

The Midwest ISO appreciates the prompt attention of NERC to the issues outlined in this request, and requests that we be kept informed of actions taken by NERC pursuant to this request.

Sincerely,

Jeffrey R. Webb
Director of Expansion Planning
Midwest ISO

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interpretation of TPL-002-0 Requirements R1.3.2 and Requirement R1.3.12 and the identical requirements (Requirements R1.3.2 and Requirement R1.3.12) in TPL-003-0 for MISO

Request for Interpretation received from MISO on August 9:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

R1.3.2	Cover critical system conditions and study years as deemed appropriate by the responsible entity.

The following interpretation of TPL-002-0 and TPL-003-0 R1.3.2 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002 and TPL-003 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions. The selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority/Transmission Planner.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 received from MISO on August 9:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

> *The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by

NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

R1.3.12	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

The interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on September 12, 2007

TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed are within the discretion of the Planning Authority/Transmission Planner.

Maureen E. Long
Standards Process Manager

November 5, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement:
Three Pre-ballot Windows and Ballot Pools for Interpretations
Open November 5, 2007

The Standards Committee (SC) announces the following standards actions:

Pre-ballot Window and Ballot Pool for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren Both Open November 5, 2007

Ameren submitted a Request for an Interpretation of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements.

The request asked if TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 require multiple contingent generating unit outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be operated in accordance with the contingency definitions included in Table 1. The request also asked if TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 require that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

The Interpretation clarifies that TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions and clarifies that the selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority and the Transmission Planner. The interpretation also states that TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is within the discretion of the Planning Authority and the Transmission Planner.

A new ballot pool to vote on this interpretation has been formed and will remain open up until 8 a.m. (EST) Tuesday, December 4, 2007. During the pre-ballot window, members of the ballot pool may communicate with one another by using their “ballot pool list server.” The list server for this ballot pool is: bp_Interpret_TPL_Ameren_in@ner.com

The initial ballot for this interpretation will begin at 8 a.m. (EST) on Tuesday, December 4, 2007.

Pre-ballot Window and Ballot Pool for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO Both Open November 5, 2007

MISO submitted a Request for an Interpretation of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements.

The request asked if TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asked if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios.

The request also asked if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

The Interpretation clarifies that TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions and clarifies that the selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority and the Transmission Planner. The interpretation also states that TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is within the discretion of the Planning Authority and the Transmission Planner.

A new ballot pool to vote on this interpretation has been formed and will remain open up until 8 a.m. (EST) Tuesday, December 4, 2007. During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." The list server for this ballot pool is: bp_Interpret_TPL_MISO_in@nerc.com

The initial ballot for this interpretation will begin at 8 a.m. (EST) on Tuesday, December 4, 2007.

Pre-ballot Window and Ballot Pool for Interpretation of VAR-001-0 Requirement R4 for Dynegy Both Open November 5, 2007

Dynegy submitted a Request for an Interpretation of VAR-001-1 Requirement R4.

The request asked if the Transmission Operator is implicitly required to have a technical basis for specifying the voltage or reactive power schedule, asked if the voltage or reactive power schedule must be reasonable and practical for the Generator Operator to maintain, and asked what measure should be used to determine if the Transmission Operator has issued a technically based, reasonable and practical voltage or reactive power schedule.

The Interpretation clarifies that VAR-001-1 is only comprised of stated requirements and associated measures and compliance elements. Interpreting an 'implicit' requirement would effectively be adding a new requirement to the standard and needs to be achieved with a Standard Authorization Request (SAR) to modify the standard rather than through an Interpretation. There are no requirements in VAR-001-1 to issue a "technically based, reasonable and practical to maintain voltage or reactive power schedule and associated tolerance band."

A new ballot pool to vote on this interpretation has been formed and will remain open up until 8 a.m. (EST) Tuesday, December 4, 2007. During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." The list server for this ballot pool is: bp_Interpret_VAR_Dynegy_in@nerc.com

The initial ballot for this interpretation will begin at 8 a.m. (EST) on Tuesday, December 4, 2007.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Jeff Webb
Director Expansion Planning
Direct Dial: 317-249-5412
E-mail: jwebb@midwestiso.org

August 9, 2007

Maureen E. Long
Standards Process Manager
North American Electric Reliability Council
Princeton Forrestal Village
116-390 Village Boulevard
Princeton, New Jersey 0854-5721

Re: Request for Interpretation of NERC Standard TPL-002-0 and TPL-003-0

Ms. Long:

The Midwest Independent Transmission System Operator, Inc. (Midwest ISO) requests a formal interpretation of two sub requirements that are common to NERC standards TPL-002-0 and TPL-003-0, in accordance with the NERC Reliability Standards Development Procedure. The sub-requirements in question are Requirements R1.3.2 and R 1.3.12 of TPL-002 and TPL-003:

> R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
>
> R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

With respect to these two requirements, and more globally in the general application of the TPL standards, the Midwest ISO requests that NERC provide guidance with respect to the following application of the TPL standards:

1. The application of the TPL contingency requirements of Table 1 to dispatch patterns considered appropriate by the entity responsible for compliance is not a misapplication of the standard as it is within the bounds of discretion that the standard permits of the Transmission Planner and the Planning Authority as entities responsible for compliance, and;

2. The application of a standard in accordance with an existing interpretation based on the history and development of the standards is appropriate, notwithstanding future interpretations or revisions of the standard.

Specifically, with respect to the discretion that the TPL standard grants to the Transmission Planner and the Planning Authority, the Midwest ISO seeks NERC interpretation of following:

Q1.1: Do the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards?

Q1.2: If in the judgment of the entity responsible for compliance, a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch patterns?

With respect to the interpretation of R1.3.12 the Midwest ISO seeks NERC interpretation of the following:

Q2.1: Does the term "planned outages" mean only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

Q2.2: If it is intended to include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision? The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, redispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

Q2.3: If it is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard[1]?

Q2.4: If NERC provides a new interpretation of a standard, or an interpretation that is different than a prior clarification by NERC of a standard, or if NERC revises a standard, would the previous application of the standard according to the clarification, interpretation, or

[1] The NERC PSS provided responses to industry questions about the Planned Outage provision of Standard IA in September 2000, and the NERC office has these responses in their archives and has provided these to the Midwest ISO.

version of a standard in effect at the time it was applied be considered a proper application of the standard? Is the more recent interpretation deemed to be retroactive, invalidating previous planning studies?

Material Impact of Standards Interpretation

- Necessary transmission expansions may not be pursued depending on the interpretation of these issues. Regulatory authorities may not permit recovery of costs of appropriately planned transmission expansions if the NERC standards are construed to prescribe the precise system conditions that are appropriate to be planned for without permitting discretion in planning assumptions to be within the proper application of the NERC standards.

- The application of the NERC standards must permit that discretion be given to Transmission Planners and Planning Authorities to apply appropriate planning assumptions for their systems in development of planning models that the NERC standards are applied to. If the NERC standards are interpreted as specifically prescribing the generation patterns, including the number of generators off-line that it is prudent to plan for, it will make it difficult for Transmission Planners and Planning Authorities to plan their specific systems to perform reliably based on their experience with and the historical performance of their systems.

- If the interpretation, reinterpretation, or revision of a standard subsequent to the application of a standard to support the need for reliability upgrades renders the prior application of a standard inappropriate in NERC's view, this would create great uncertainty in the ability of a Transmission owner to recover costs for upgrades, and would result in reluctance by Transmission Owners to expand their systems based on present interpretations of the standards.

The Midwest ISO appreciates the prompt attention of NERC to the issues outlined in this request, and requests that we be kept informed of actions taken by NERC pursuant to this request.

Sincerely,

Jeffrey R. Webb
Director of Expansion Planning
Midwest ISO

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot of the Interpretation of Requirements R1.3.2 and R1.3.12 in TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements for MISO

Summary Consideration: Although most balloters agreed with the interpretation, several stakeholders indicated that the interpretation doesn't adequately address the questions that were asked in the request for the interpretation. Based on these stakeholder comments, the Planning Committee, serving as the drafting team, has revised the interpretation for both R1.3.2 and R1.3.12:

> With regard to R1.3.2, the committee revised its interpretation to clearly state that the Regional Entity, as the Compliance Monitor determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner.
>
> With regard to R1.3.12, the committee revised its interpretation to clearly state that planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.1

[1] The appeals process is in the Reliability Standards Process Manual: http://www.nerc.com/standards/newstandardsprocess.html.

Voter	Entity	Segment	Vote	Comment
Kirit S. Shah	Ameren Services Company	1	Negative	Comments 1.3.2 (1) The interpretation is non-responsive to the request in that it provides no insight as to how the responsible entities should consider the requirement so as to be compliant. (2) The question is not whether the TPL standards should include consideration of sensitivity to various generation dispatch patterns. The issue is whether this sensitivity should include consideration of non-firm transactions contrary to the explicit language in Requirements R1 and R1.3.5. Comments on R1.3.12 (1) The interpretation is non-responsive to the request in that it provides no insight as to how the responsible entities should consider the requirement so as to be compliant. (2) The interpretation is not consistent with the interpretation submitted by the NERC PC as reflected in the meeting minutes of the NERC PC.
Response: The Planning Committee thanks you for your comment. With regard to R1.3.2, the committee has revised its interpretation. The Regional Entity, as the Compliance Monitor, determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. With regard to R1.3.12, the committee has revised its interpretation. Planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages.				
Robert G. Coish Ronald Dacombe Mark Aikens Daniel Prowse	Manitoba Hydro	1 3 5 6	Negative	The interpretation outlined in R1.3.2 accurately reflects the Planning Committee's intent; however, the interpretation for R1.3.12 does not. The interpretation for R1.3.12 fails to include the phrase 'including any necessary system adjustments prior to application of the contingency" which is critical to the NERC Planning Committee interpretation.
Response: The Planning Committee thanks you for your comment. With regard to R1.3.2, the committee has revised its interpretation. The Regional Entity, as the Compliance Monitor, determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. With regard to R1.13.12, the committee has revised its interpretation. Planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages.				

Voter	Entity	Segment	Vote	Comment
Michael J Ranalli Michael Schiavone	National Grid Niagara Mohawk (National Grid Company)	1 3	Affirmative	The interpretation states "Planning Authority/Transmission Planner". The "/" can be interpreted as either an "and" or an "or". In order to be consistent with the Reliability Standard TPL-002 and TPL-003 Requirement R1, the interpretations should state "Planning Authority and Transmission Planner". Therefore we think the interpretations for TPL-002-0 and TPL-003-0 R1.3.2 and R1.3.12 should have the "/" replaced with an "and".
Response: The Planning Committee thanks you for your comment. With regard to R1.3.2, the committee has revised its interpretation. The Regional Entity, as the Compliance Monitor, determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. With regard to R1.13.12, the committee has revised its interpretation. Planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages. These revised interpretations do not refer to the Planning Coordinator (formerly named the Planning Authority) or the Transmission Planner.				
Richard J. Kafka	Potomac Electric Power Co.	1	Negative	I do not believe the interpretations shown for ballot reflect the motion approved by the Planning Committee. There has been a round of emails from the Planning Committee, and the Executive Board says there was no intentional change, but I still believe the interpretation does not reflect what the PC said. In essence, what is missing, is that the PC said planning for contingencies should reflect operations in that the system would have been reconfigured (re-dispatch, switching, etc.) to provide N-1 reliability for any planned outages. That is, you don't just use the starting base case (dispatch) for all planned outages.
Response: The Planning Committee thanks you for your comment. The committee agrees and has revised its interpretation to R1.13.12. Planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages.				
Hubert C. Young	South Carolina Electric & Gas Co.	3	Negative	SCE&G believes this interpretation needs additional clarification. The NERC "Glossary of Terms" defines contingency as "The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element". A planned outage is NOT unexpected and therefore is not a contingency, based on this definition. SCE&G suggest that the standard specifically state if planned maintenance 1) is part of the event in Table 1 or 2) is a change in base conditions that are tested against Table 1. Without this clarification the industry will be planning at different levels base on individual interpretation of this standard.

Voter	Entity	Segment	Vote	Comment
Response: The Planning Committee thanks you for your comment. The committee agrees and has revised its interpretation to R1.13.12. Planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages.				
James A. Maenner	Wisconsin Public Service Corp.	3	Negative	This interpretation is a disappointment; deferring the question back to the planning authority does not address the request for interpretation. Allowing individual Transmission Planners/Planning Authorities this discretion opens the door to wide variation across the interconnection.
Response: The Planning Committee thanks you for your comment. It is unclear if the comment provided is related to the interpretation provided for R1.3.2, R1.3.12 or a general statement related to each. In any case, we have revised our previous interpretations. With regard to R1.3.2, the committee has revised its interpretation. The Regional Entity, as the Compliance Monitor, determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. With regard to R1.3.12, planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages.				
Christopher Plante	WPS Resources Corp.	4	Negative	The "interpretation" developed for this standard essentially defers back to the Planning Authority to make its own interpretation of the standard. Allowing each Planning Authority to make its own interpretation of a Reliability Standard defeats the purpose of having a standard. NERC should strive to develop clear and concise interpretations of its Standards that do not simply defer back to the responsible entity. A much more reasonable interpretation of this standard was developed and approved by the NERC Planning Committee at their September 2007 meeting.
Response: The Planning Committee thanks you for your comment. With regard to R1.3.2, the committee has revised its interpretation. The Regional Entity, as the Compliance Monitor, determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. With regard to R1.13.12, the committee has revised its interpretation. Planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages.				
Karl E. Kohlrus	City Water, Light & Power of Springfield	5	Negative	The interpretation does not provide guidance as to how to determine compliance but only suggests that this requirement is subject to the discretion of the Planning Authority/Transmission Planner. As such it is unclear how to consistently and comparably assess compliance within a Planning Authority’s footprint and across

Voter	Entity	Segment	Vote	Comment
				NERC.
Response: The Planning Committee thanks you for your comment. With regard to R1.3.2, the committee has revised its interpretation. The Regional Entity, as the Compliance Monitor, determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. With regard to R1.13.12, the committee has revised its interpretation. Planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages.				
William Franklin	Entergy Services, Inc.	6	Negative	The interpretation does not adequately address the 2nd question regarding R1.3.12, and furthermore the standards do not "explicitly" provide that inclusion of the questioned activities is within the discretion of the Planning Authority/Transmission Planner.
Response: The Planning Committee thanks you for your comment. With regard to R1.13.12, the committee has revised its interpretation. Planned outages are not contingencies, and it is appropriate that studies that include planned outages include any necessary system adjustments needed to accommodate such outages.				
Charles H. Yeung	Southwest Power Pool	10	Affirmative	It appears that the recent influx of interpretations could be better addressed in technical forums such as NERC committees or on a web-based forum. Since, many of the interpretation responses leave it up to the requestor to submit SARs to add language into the requirements, more interactive communications with the requestor would aid that party's understanding.
Response: The Planning Committee thanks you for your comment. Your recommendation has been noted and will be further explored. NERC is always looking for ways to improve the standards development process.				

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standards

Ballot Results	
Ballot Name:	Interpretation Request for TPL-002-003 - MISO_in
Ballot Period:	12/4/2007 - 12/13/2007
Ballot Type:	Initial
Total # Votes:	161
Total Ballot Pool:	187
Quorum:	**86.10 % The Quorum has been reached**
Weighted Segment Vote:	87.50 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	59	1	45	0.918	4	0.082	3	7
2 - Segment 2.	8	0.7	7	0.7	0	0	1	0
3 - Segment 3.	48	1	32	0.8	8	0.2	1	7
4 - Segment 4.	8	0.6	4	0.4	2	0.2	1	1
5 - Segment 5.	32	1	16	0.8	4	0.2	6	6
6 - Segment 6.	17	1	12	0.857	2	0.143	0	3
7 - Segment 7.	1	0.1	1	0.1	0	0	0	0
8 - Segment 8.	2	0.2	2	0.2	0	0	0	0
9 - Segment 9.	7	0.6	6	0.6	0	0	0	1
10 - Segment 10.	5	0.4	4	0.4	0	0	0	1
Totals	**187**	**6.6**	**129**	**5.775**	**20**	**0.825**	**12**	**26**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	AEP Service Corp. -- Transmission System AEP	Scott P. Moore	Affirmative	
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services Company	Kirit S. Shah	Negative	View
1	Arizona Public Service Co.	Cary B. Deise	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott Kinney	Abstain	
1	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins		
1	CenterPoint Energy	Paul Rocha	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Consolidated Edison Co. of New	Edwin E. Thompson PE	Affirmative	

	York			
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	William L. Thompson	Affirmative	
1	Duke Energy Carolina	Doug Hils	Affirmative	
1	Entergy Corporation	George R. Bartlett	Negative	
1	Exelon Energy	John J. Blazekovich	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	C. Martin Mennes	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg		
1	Idaho Power Company	Ronald D. Schellberg	Abstain	
1	ITC Transmission	Brian F. Thumm		
1	JEA	Ted E. Hobson	Affirmative	
1	Kansas City Power & Light Co.	Jim Useldinger	Affirmative	
1	Keyspan LIPA	Richard J. Bolbrock	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	Manitoba Hydro	Robert G. Coish	Negative	View
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	National Grid	Michael J Ranalli	Affirmative	View
1	Nebraska Public Power District	Richard L. Koch	Affirmative	
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Affirmative	
1	New York Power Authority	Ralph Rufrano	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Joseph Dobes	Affirmative	
1	Oncor Electric Delivery	Charles W. Jenkins	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	
1	PacifiCorp	Robert Williams	Affirmative	
1	Potomac Electric Power Co.	Richard J. Kafka	Negative	View
1	PP&L, Inc.	Ray Mammarella		
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Sacramento Municipal Utility District	Dilip Mahendra		
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Christopher M. Turner	Affirmative	
1	Southern California Edison Co.	Dana Cabbell		
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Indiana Gas and Electric Co.	Michael Chambliss	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Tri-State G & T Association Inc.	Bruce A Sembrick	Affirmative	
1	Tucson Electric Power Co.	Ronald P. Belval	Affirmative	
1	Western Area Power Administration	Robert Temple	Affirmative	
2	Alberta Electric System Operator	Anita Lee	Affirmative	
2	British Columbia Transmission Corporation	Phil Park	Affirmative	

2	California ISO	David Hawkins	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Roy D. McCoy	Abstain	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
3	Alabama Power Company	Robin Hurst	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Negative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl		
3	City of Tallahassee	Rusty S. Foster	Affirmative	
3	City Public Service of San Antonio	Edwin Les Barrow	Affirmative	
3	Commonwealth Edison Co.	Stephen Lesniak	Affirmative	
3	Consumers Energy Co.	David A. Lapinski	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr		
3	Entergy Services, Inc.	Matt Wolf	Negative	
3	Farmington Electric Utility System	Alan Glazner	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	
3	Florida Municipal Power Agency	Michael Alexander		
3	Florida Power & Light Co.	W.R. Schoneck	Affirmative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone		
3	JEA	Garry Baker	Affirmative	
3	Kissimmee Utility Authority	Gregory David Woessner	Negative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Ronald Dacombe	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Christopher Lawrence de Graffenried	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	View
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PECO Energy an Exelon Co.	John J. McCawley		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Negative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Negative	View
3	Southern Indiana Gas and Electric Co.	Fred Frederick	Affirmative	
3	Tennessee Valley Authority	Cynthia Herron		

3	Wisconsin Electric Power Marketing	James R. Keller	Affirmative	
3	Wisconsin Public Service Corp.	James A. Maenner	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	American Municipal Power - Ohio	Chris Norton	Abstain	
4	Consumers Energy Co.	David Frank Ronk	Affirmative	
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski		
4	WPS Resources Corp.	Christopher Plante	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin		
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Negative	View
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Abstain	
5	Conectiv Energy Supply, Inc.	Richard K. Douglass	Negative	
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dynegy	Greg Mason	Negative	
5	Entergy Corporation	Stanley M Jaskot		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	Douglas Keegan		
5	Florida Power & Light Co.	Robert A. Birch	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Lincoln Electric System	Dennis Florom		
5	Louisville Gas and Electric Co.	Charlie Martin	Abstain	
5	Manitoba Hydro	Mark Aikens	Negative	View
5	New York Power Authority	Richard J. Ardolino	Affirmative	
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	Reliant Energy Services	Thomas J. Bradish	Abstain	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Southeastern Power Administration	Douglas Spencer	Abstain	
5	Southern Company Services, Inc.	Roger D. Green	Affirmative	
5	Southern Indiana Gas and Electric Co.	Mark Rose	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Xcel Energy, Inc.	Stephen J. Beuning		
6	AEP Service Corp.	Dana E. Horton	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson		
6	Entergy Services, Inc.	William Franklin	Negative	View
6	Exelon Power Team	Pulin Shah	Affirmative	
6	First Energy Solutions	Alfred G. Roth	Affirmative	
6	Florida Municipal Power Agency	Robert C. Williams		
6	Great River Energy	Donna Stephenson	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	PP&L, Inc.	Thomas Hyzinski	Affirmative	
6	Progress Energy Carolinas	James Eckelkamp	Affirmative	
	Public Utility District No. 1 of Chelan			

6	County	Hugh A. Owen	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Southern Company Generation and Energy Marketing	J. Roman Carter	Affirmative	
6	Southern Indiana Gas and Electric Co.	Brad Lisembee	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons		
7	Eastman Chemical Company	Lloyd Webb	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Other	Michehl R. Gent	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Public Service Commission	James T. Gallagher		
9	North Carolina Utilities Commission	Kimberly J. Jones	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Affirmative	
9	Wyoming Public Service Commission	Steve Oxley	Affirmative	
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Midwest Reliability Organization	Larry Brusseau		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Edward A. Schwerdt	Affirmative	
10	Southwest Power Pool	Charles H. Yeung	Affirmative	View

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Maureen E. Long
Standards Process Manager

December 14, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement of Initial Ballot Results for Three Interpretations

The Standards Committee (SC) announces the following:

Initial Ballot Results for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren

The initial ballot for the Interpretation (for Ameren) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements was conducted from December 4–13, 2007.

The request for interpretation asked if TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 require multiple contingent generating unit outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be operated in accordance with the contingency definitions included in Table 1. The request also asked if TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 require that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

The Interpretation clarifies that TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions and clarifies that the selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority and the Transmission Planner. The interpretation also states that TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is within the discretion of the Planning Authority and the Transmission Planner.

The ballot achieved a quorum; however, there were some negative ballots with comments, initiating the need to review the comments and determine whether the interpretation needs modification before proceeding to a re-circulation ballot. The drafting team will be reviewing comments submitted with the ballot and preparing its consideration of those comments. (Detailed Ballot Results)

Quorum: 86.70 %
Approval: 88.10 %

Initial Ballot Results for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO

The initial ballot for the Interpretation (for MISO) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements, was conducted from December 4–13, 2007.

The request for interpretation asked if TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards. MISO then asked if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios. The request also asked if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

The Interpretation clarifies that TPL-002-0 R1.3.2 and TPL-003-0 R1.3.2 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions and clarifies that the selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority and the Transmission Planner. The interpretation also states that TPL-002-0 R1.3.12 and TPL-003-0 R1.3.12 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is within the discretion of the Planning Authority and the Transmission Planner.

The ballot achieved a quorum, however there were some negative ballots with comments, initiating the need to review the comments and determine whether the interpretation needs modification before proceeding to a re-circulation ballot. The drafting team will be reviewing comments submitted with the ballot and preparing its consideration of those comments. (Detailed Ballot Results)

Quorum:	86.10 %
Approval:	87.50 %

Initial Ballot Results for Interpretation of VAR-001-0 Requirement R4 for Dynegy

The initial ballot for the Interpretation (for Dynegy) of VAR-001-0 — Voltage and Reactive Control, Requirement R4, was conducted from December 4–13, 2007.

The request for interpretation asked if the Transmission Operator is implicitly required to have a technical basis for specifying the voltage or reactive power schedule; asked if the voltage or reactive power schedule must be reasonable and practical for the Generator Operator to maintain; and asked what measure should be used to determine if the Transmission Operator has issued a technically based, reasonable and practical voltage or reactive power schedule.

The Interpretation clarifies that VAR-001-1 is only comprised of the stated requirements and associated measures and compliance elements. Interpreting an "implicit" requirement would effectively be adding a new requirement to the standard and needs to be achieved with a Standard Authorization Request (SAR) to modify the standard rather than through an Interpretation. There are no requirements in VAR-001-1 to issue a "technically based, reasonable and practical to maintain voltage or reactive power schedule and associated tolerance band."

The ballot achieved a quorum; however, there were some negative ballots with comments, initiating the need to review the comments and determine whether the interpretation needs modification before proceeding to a re-circulation ballot. The drafting team will be reviewing comments submitted with the ballot and preparing its consideration of those comments. (Detailed Ballot Results)

Quorum: 86.41 %
Approval: 93.00 %

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Interpretation of TPL-002-0 Requirement R1.3.2 and Requirement R1.3.12 and the Identical Requirements (R1.3.2 and R1.3.12) in TPL-003-0 for MISO

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

> From TPL-002-0 and -003-0:
>
> [To be valid, the Planning Authority and Transmission Planner assessments shall:]
>
> **R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002 and TPL-003 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions. The selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority/Transmission Planner.

The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion

plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

From TPL-002-0 and -003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed are within the discretion of the Planning Authority/Transmission Planner.

The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Barbara Bogenrief

From: Barbara Bogenrief
Sent: Monday, March 24, 2008 10:34 AM
To: Barbara Bogenrief
Subject: NERC Standards Announcement - Pre-ballot Windows and Ballot Pools Open for Two Interpretations

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Pre-ballot Windows and Ballot Pools Open for Two Interpretations
March 24, 2008–April 23, 2008

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Pre-ballot Window and Ballot Pool for Revised Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren Opens March 24, 2008

Ameren submitted a Request for an Interpretation of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements.

The Planning Committee (drafting team) provided an interpretation that underwent an initial ballot from December 4–13, 2007. While the initial ballot achieved a quorum (86.70%) and a high affirmative vote (88.10%), some comments submitted with ballots indicated that the interpretation didn't fully address the questions asked, and the drafting team added some clarifying language to the interpretation. The drafting team's revised interpretation is posted for a new 30-day pre-ballot review.

The ballot pool to vote on this interpretation has been re-opened and will remain open up until 8 a.m. (EDT) Wednesday, April 23, 2008. During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." The list server for this ballot pool is: bp_Interpret_TPL_Ameren_in@ner.com

The initial ballot for this interpretation will begin at 8 a.m. (EDT) on Wednesday, April 23, 2008.

Pre-ballot Window and Ballot Pool for Revised Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO Opens March 24, 2008

MISO submitted a Request for an Interpretation of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements.

The Planning Committee (drafting team) provided an interpretation that underwent an initial ballot from December 4-13, 2007. While the initial ballot achieved a quorum (86.10%) and a high affirmative vote (87.50%), some comments submitted with ballots indicated that the interpretation didn't fully address the questions asked, and the drafting team added some clarifying language to the interpretation. The drafting team's revised interpretation is posted for a new 30-day pre-ballot review.

The ballot pool to vote on this interpretation has been re-opened and will remain open up until 8 a.m. (EDT) Wednesday, April 23, 2008. During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." The list server for this ballot pool is: bp_Interpret_TPL_MISO_in@nerc.com

The initial ballot for this interpretation will begin at 8 a.m. (EDT) on Wednesday, April 23, 2008.

Standards Development Procedure

The *Reliability Standards Development Procedure Manual* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

North American Electric Reliability Corporation
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Jeff Webb
Director Expansion Planning
Direct Dial: 317-249-5412
E-mail: jwebb@midwestiso.org

August 9, 2007

Maureen E. Long
Standards Process Manager
North American Electric Reliability Council
Princeton Forrestal Village
116-390 Village Boulevard
Princeton, New Jersey 0854-5721

Re: Request for Interpretation of NERC Standard TPL-002-0 and TPL-003-0

Ms. Long:

The Midwest Independent Transmission System Operator, Inc. (Midwest ISO) requests a formal interpretation of two sub requirements that are common to NERC standards TPL-002-0 and TPL-003-0, in accordance with the NERC Reliability Standards Development Procedure. The sub-requirements in question are Requirements R1.3.2 and R 1.3.12 of TPL-002 and TPL-003:

> R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
>
> R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

With respect to these two requirements, and more globally in the general application of the TPL standards, the Midwest ISO requests that NERC provide guidance with respect to the following application of the TPL standards:

1. The application of the TPL contingency requirements of Table 1 to dispatch patterns considered appropriate by the entity responsible for compliance is not a misapplication of the standard as it is within the bounds of discretion that the standard permits of the Transmission Planner and the Planning Authority as entities responsible for compliance, and;

2. The application of a standard in accordance with an existing interpretation based on the history and development of the standards is appropriate, notwithstanding future interpretations or revisions of the standard.

Specifically, with respect to the discretion that the TPL standard grants to the Transmission Planner and the Planning Authority, the Midwest ISO seeks NERC interpretation of following:

Q1.1: Do the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards?

Q1.2: If in the judgment of the entity responsible for compliance, a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch patterns?

With respect to the interpretation of R1.3.12 the Midwest ISO seeks NERC interpretation of the following:

Q2.1: Does the term "planned outages" mean only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

Q2.2: If it is intended to include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision? The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, redispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

Q2.3: If it is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard[1]?

Q2.4: If NERC provides a new interpretation of a standard, or an interpretation that is different than a prior clarification by NERC of a standard, or if NERC revises a standard, would the previous application of the standard according to the clarification, interpretation, or

[1] The NERC PSS provided responses to industry questions about the Planned Outage provision of Standard IA in September 2000, and the NERC office has these responses in their archives and has provided these to the Midwest ISO.

version of a standard <u>in effect at the time it was applied</u> be considered a proper application of the standard? Is the more recent interpretation deemed to be retroactive, invalidating previous planning studies?

Material Impact of Standards Interpretation

- Necessary transmission expansions may not be pursued depending on the interpretation of these issues. Regulatory authorities may not permit recovery of costs of appropriately planned transmission expansions if the NERC standards are construed to prescribe the precise system conditions that are appropriate to be planned for without permitting discretion in planning assumptions to be within the proper application of the NERC standards.

- The application of the NERC standards must permit that discretion be given to Transmission Planners and Planning Authorities to apply appropriate planning assumptions for their systems in development of planning models that the NERC standards are applied to. If the NERC standards are interpreted as specifically prescribing the generation patterns, including the number of generators off-line that it is prudent to plan for, it will make it difficult for Transmission Planners and Planning Authorities to plan their specific systems to perform reliably based on their experience with and the historical performance of their systems.

- If the interpretation, reinterpretation, or revision of a standard subsequent to the application of a standard to support the need for reliability upgrades renders the prior application of a standard inappropriate in NERC's view, this would create great uncertainty in the ability of a Transmission owner to recover costs for upgrades, and would result in reluctance by Transmission Owners to expand their systems based on present interpretations of the standards.

The Midwest ISO appreciates the prompt attention of NERC to the issues outlined in this request, and requests that we be kept informed of actions taken by NERC pursuant to this request.

Sincerely,

Jeffrey R. Webb
Director of Expansion Planning
Midwest ISO

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interpretation of TPL-002-0 Requirement R1.3.2 and Requirement R1.3.12 and the Identical Requirements (R1.3.2 and R1.3.12) in TPL-003-0 for MISO

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

> From TPL-002-0 and -003-0:
>
> [To be valid, the Planning Authority and Transmission Planner assessments shall:]
>
> **R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on September 12, 2007:
TPL-002 and TPL-003 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions. The selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority/Transmission Planner.

The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:
The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion

plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

From TPL-002-0 and -003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed are within the discretion of the Planning Authority/Transmission Planner.

The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

Barbara Bogenrief

From: Barbara Bogenrief [Barbara.Bogenrief@nerc.net]
Sent: Thursday, April 24, 2008 9:33 AM
To: Barbara Bogenrief
Subject: NERC Standards Announcement - Ballot Window Opens for Two Interpretations

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Ballot Window Opens for Two Interpretations

April 25–May 5, 2008

Now available at: http://www.nerc.com/~filez/standards/Reliability_Standards_Under_Development.html

Ballot Window for Revised Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren Opens Friday, April 25, 2008

The initial ballot for the revised interpretation (for Ameren) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements, will open at 8 a.m. (EDT) on Friday, April 25, 2008.

The Planning Committee (drafting team) provided an interpretation that underwent an initial ballot from December 4–13, 2007. While the initial ballot achieved a quorum (86.70%) and a high affirmative vote (88.10%), some comments submitted with ballots indicated that the interpretation didn't fully address the questions asked, and the drafting team added some clarifying language to the interpretation. The initial ballot for the revised interpretation will close at 8 p.m. (EDT) on Monday, May 5, 2008.

Ballot Window for Revised Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO Opens Friday, April 25

The initial ballot for the revised interpretation (for MISO) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements, will open at 8 a.m. (EDT) on Friday, April 25, 2008.

The Planning Committee (drafting team) provided an interpretation that underwent an initial ballot from December 4–13, 2007. While the initial ballot achieved a quorum (86.70%) and a high affirmative vote (88.10%), some comments submitted with ballots indicated that the interpretation didn't fully address the questions asked, and the drafting team added some clarifying language to the interpretation. The initial ballot for the revised interpretation will close at 8 p.m. (EDT) on Monday, May 5, 2008.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

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Jeff Webb
Director Expansion Planning
Direct Dial: 317-249-5412
E-mail: jwebb@midwestiso.org

August 9, 2007

Maureen E. Long
Standards Process Manager
North American Electric Reliability Council
Princeton Forrestal Village
116-390 Village Boulevard
Princeton, New Jersey 0854-5721

Re: Request for Interpretation of NERC Standard TPL-002-0 and TPL-003-0

Ms. Long:

The Midwest Independent Transmission System Operator, Inc. (Midwest ISO) requests a formal interpretation of two sub requirements that are common to NERC standards TPL-002-0 and TPL-003-0, in accordance with the NERC Reliability Standards Development Procedure. The sub-requirements in question are Requirements R1.3.2 and R 1.3.12 of TPL-002 and TPL-003:

> R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
>
> R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

With respect to these two requirements, and more globally in the general application of the TPL standards, the Midwest ISO requests that NERC provide guidance with respect to the following application of the TPL standards:

1. The application of the TPL contingency requirements of Table 1 to dispatch patterns considered appropriate by the entity responsible for compliance is not a misapplication of the standard as it is within the bounds of discretion that the standard permits of the Transmission Planner and the Planning Authority as entities responsible for compliance, and;

2. The application of a standard in accordance with an existing interpretation based on the history and development of the standards is appropriate, notwithstanding future interpretations or revisions of the standard.

Specifically, with respect to the discretion that the TPL standard grants to the Transmission Planner and the Planning Authority, the Midwest ISO seeks NERC interpretation of following:

Q1.1: Do the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards?

Q1.2: If in the judgment of the entity responsible for compliance, a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch patterns?

With respect to the interpretation of R1.3.12 the Midwest ISO seeks NERC interpretation of the following:

Q2.1: Does the term "planned outages" mean only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

Q2.2: If it is intended to include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision? The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, redispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

Q2.3: If it is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard[1]?

Q2.4: If NERC provides a new interpretation of a standard, or an interpretation that is different than a prior clarification by NERC of a standard, or if NERC revises a standard, would the previous application of the standard according to the clarification, interpretation, or

[1] The NERC PSS provided responses to industry questions about the Planned Outage provision of Standard IA in September 2000, and the NERC office has these responses in their archives and has provided these to the Midwest ISO.

version of a standard <u>in effect at the time it was applied</u> be considered a proper application of the standard? Is the more recent interpretation deemed to be retroactive, invalidating previous planning studies?

Material Impact of Standards Interpretation

- Necessary transmission expansions may not be pursued depending on the interpretation of these issues. Regulatory authorities may not permit recovery of costs of appropriately planned transmission expansions if the NERC standards are construed to prescribe the precise system conditions that are appropriate to be planned for without permitting discretion in planning assumptions to be within the proper application of the NERC standards.

- The application of the NERC standards must permit that discretion be given to Transmission Planners and Planning Authorities to apply appropriate planning assumptions for their systems in development of planning models that the NERC standards are applied to. If the NERC standards are interpreted as specifically prescribing the generation patterns, including the number of generators off-line that it is prudent to plan for, it will make it difficult for Transmission Planners and Planning Authorities to plan their specific systems to perform reliably based on their experience with and the historical performance of their systems.

- If the interpretation, reinterpretation, or revision of a standard subsequent to the application of a standard to support the need for reliability upgrades renders the prior application of a standard inappropriate in NERC's view, this would create great uncertainty in the ability of a Transmission owner to recover costs for upgrades, and would result in reluctance by Transmission Owners to expand their systems based on present interpretations of the standards.

The Midwest ISO appreciates the prompt attention of NERC to the issues outlined in this request, and requests that we be kept informed of actions taken by NERC pursuant to this request.

Sincerely,

Jeffrey R. Webb
Director of Expansion Planning
Midwest ISO

Consideration of Comments on Initial Ballot of Revised Interpretation of TPL-002 and TPL-003 — Requirements 1.3.2 and 1.3.12 for MISO

Summary Consideration: The drafting team corrected a typographical error in the last paragraph of the interpretation, but did not make any other modifications to the interpretation based on the comments submitted.

Correction:
TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is required.

Segment	Organization	Comment
1	Ameren Services Company	TPL-002-0 Requirement R.1.3.2: Do Not Approve. Comments: The proposed interpretation of R1.3.2 does not answer the following basic question with respect to the TPL standards: Does including contingent outages as part of the defined operating state exceed the contingency requirements specified in Table 1 of the TPL standards? Defining contingent outages in the assumed system operating state is not consistent with FAC or TPL standards. FAC-010 specifies in Requirement R2.1 In the pre-contingency state with all Facilities in service TPL-002-0 Requirement R1 provides the general description for the reliability assessment of the system. R1 states that the system shall be studied under the contingency conditions as defined in Category B of Table 1. How does the interpretation address the inconsistency of modeling contingent outages as critical system conditions outside of Table 1? Could a Transmission Planner or Planning Coordinator (Authority) specify one or more contingent transmission facility outages in their critical system conditions? The contentious application of “critical system conditions” did not apply to the specification of a base case dispatch scenario. The Planning Coordinator performed a First Contingency Incremental Transfer Capability (FCITC) analysis which modeled non-firm transactions to replace contingent generation outages. Does compliance with TLP-002 require sufficient import capability to provide access to external generation capacity for which there are not explicit capacity or transmission reservations at the discretion of the Planning Coordinator? FAC-012-1, Transfer Capability Methodology, requires that the Planning Coordinator (Authority) to document its current methodology used for developing its inter-regional and intra-regional Transfer Capabilities (Transfer Capability Methodology). Does this interpretation suggest that the Planning Coordinator has the requirement or responsibility to define a minimum level of transfer capability? Is it the intent of this interpretation that a Planning Coordinator’s transfer capability methodology be applied to TPL standards compliance? The draft interpretation states that the selection of a credible generation dispatch for modeling of critical system conditions is within the discretion of the

Segment	Organization	Comment
		Planning Coordinator: which of the current standards establishes a requirement that the Planning Coordinator develop a methodology to determine base case dispatch scenarios or gives the Planning Coordinator the authority to prescribe dispatch assumptions?
Response: We thank you for your comments, which address R1.3.2. However, most of the questions posed go well beyond the subject matter of the interpretation. The term "critical system conditions" is undefined in TPL-002 and TPL-003, and the standard itself gives no basis for defining it. Neither does the Functional Model, a standards reference document, provide any guidance. While this is understandably what Ameren is seeking in its comments, our interpretation could not provide a direct answer. However, we were able to articulate a process for obtaining the specificity desired by Ameren, which we reiterate below. The Functional Model language cited in the interpretation supports the Planning Coordinator's supervisory role in directing the coordination of the planning process, including the specification of any methodologies to be used by Transmission Planners in its area. Such authority is also implied by a common sense reading of the standard itself. Assume that the standard was written with the understanding that the Planning Coordinator *did not* have this authority. Each of its Transmission Planners would be free to make and adopt its own methods, and the Planning Coordinator's assessment as well as each Transmission Planner's assessment would be invalid on its face due solely to the lack of coordination. (Remember that M1 and M2 apply to both the Planning Coordinator *and* its Transmission Planners.) As we stated in the interpretation "As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters."		
1	American Transmission Company, LLC	The interpretation applies to only the Planning Coordinator while the standard R1 applies to both the Planning Coordinator and Transmission Planner. ATC believes that the proposed interpretation is assigning greater authority onto the Planning Coordinator than the requirement specifies. Lastly, ATC believe that the Functional Model Reference Document should not be used for an interpretation. (What happens if the Functional Model document is changed so that it no long supports an interpretation?)
Response: We thank you for your comments, which address R1.3.2. We respectively disagree with ATC's statement that "the proposed interpretation is assigning greater authority onto the Planning Coordinator <u>than the requirement specifies</u> (emphasis added)." The relationship between the Planning Coordinator and its Transmission Planner's is not specified *in any requirement in TPL-002 or TPL-003*. The Functional Model language cited in the interpretation supports the Planning Coordinator's supervisory role in directing the coordination of the planning process, including the specification of any methodologies to be used by Transmission Planners in its area. The Functional Model is a reference document, and as such it may be used to support the interpretation of a Reliability Standard. See NERC's *Rules of Procedures*, Appendix 3A, p. 34. We have referenced a specific Functional Model version 3, not the current Functional Model, so our interpretation would not change if the Functional Model changed.		

Segment	Organization	Comment
Such authority is also implied by a common sense reading of the standard itself, even without a reference to the Functional Model. Assume that the standard was written with the understanding that the Planning Coordinator *did not* have this authority. Each of its Transmission Planners would be free to make and adopt its own methods, and the Planning Coordinator's assessment as well as each Transmission Planner's assessment would be invalid on its face due solely to the lack of coordination. (Remember that M1 and M2 apply to both the Planning Coordinator *and* its Transmission Planners.)		
1	Duke Energy Carolina	Thank you for the opportunity to vote on this interpretation. We agreed with the September 12, 2007 Interpretation of Requirement 1.3.2, but do not agree with the March 13, 2008 Interpretation of Requirement 1.3.2, which places selection of critical system conditions under the authority of the Planning Coordinator. We agreed with the September 12, 2007 Interpretation of Requirement 1.3.12, and also agree with the March 13, 2008 Interpretation of Requirement 1.3.12.
Response: We thank you for your comments. However, since you offer no explanation as to why you disagree with R1.3.2, we can offer no response.		
1	Entergy Corporation	There are requirements in the standard that we feel are applied equally to the Transmission Planner and the Planning Coordinator. We believe that the interpretation erroneously attributes approval authority to the PC and the RE that is not called out for in the standard.
Response: We thank you for your comments. The relationship between the Planning Coordinator and the Transmission Planner is not specified in any of the requirements in TPL-002 or TPL-003. The Functional Model language cited in the interpretation supports the Planning Coordinator's supervisory role in directing the coordination of the planning process, including the specification of any methodologies to be used by Transmission Planners in its area. The Functional Model is a reference document, and as such it may be used to support the interpretation of a Reliability Standard. See NERC's *Rules of Procedures*, Appendix 3A, p. 34. We have referenced a specific Functional Model version 3, not the current Functional Model, so our interpretation would not change if the Functional Model changed. Such authority is also implied by a common sense reading of the standard itself, even without a reference to the Functional Model. Assume that the standard was written with the understanding that the Planning Coordinator *did not* have this authority. Each of its Transmission Planners would be free to make and adopt its own methods, and the Planning Coordinator's assessment as well as each Transmission Planner's assessment would be invalid on its face due solely to the lack of coordination. (Remember that M1 and M2 apply to both the Planning Coordinator *and* its Transmission Planners.)		
1	Gainesville Regional Utilities	I suggest the first sentence ending be changed from "are required" to "are performed within the discretion of the Planning Authority/Transmission Planner." This change will return the standard to its original interpretation concerning this matter and keep the volume of work hopefully within achievable limits. Secondly, the second sentence raised a concern that a planned outage should be considered a contingency which totally goes against the NERC

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		Glossary of Terms. You must allow some necessary system adjustments to accommodate this condition before running any contingency studies.
Response: We thank you for your comments, which address R1.3.12. We respectfully disagree with your suggested change in the first sentence which would make the consideration of planned outages within the discretion of the Planning Authority/Transmission Planner. R.1.3.12 is a requirement, and as such, cannot be optional or discretionary. However, the requirement does not specify a method for the modeling of planned outages; such modeling methods are within the discretion of the Planning Authority [Planning Coordinator] to specify, and those methods should be consistently used by all its Transmission Planners. We believe that Gainesville has misread our second sentence. We stated that a "planned outage is <u>not</u> [emphasis added] a "contingency" and that "necessary system adjustments" would be included prior to any contingency assessment.		
1	Manitoba Hydro	Manitoba Hydro agrees with the interpretation outlined in TPL-003-0 R1.3.12; however, Manitoba Hydro does not agree with the interpretation of TPL-002-0 and TPL-003-0 R1.3.2. The standard puts the onus of defining critical system conditions on the PA/TP. The revised interpretation creates confusion as it is now unclear as to whether the PA/TP or RE as Compliance monitor is to determine the critical system conditions.
Response: We thank you for your comments. We respectfully disagree with your conclusion regarding our interpretation of R1.3.2. The Planning Coordinator has the authority to specify "critical system conditions." As we stated in the interpretation "As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters."		
1	Northeast Utilities	There remains a necessary level of coordination between the Transmission Planner and Planning Authority to determine generation dispatch and planned outage scenarios to be used in system assessments. The revised interpretation disregards the important role of the Transmission Planner, which the Standards themselves do not. Additionally, we believe NERC has not followed its Reliability Standards Development Procedure (Version 6.1) which in Step 9, First Ballot section, the last paragraph states; however, one or more members submit negative votes with reasons, regardless whether those reasons are resolved or not, a second ballot shall be conducted. NERC failed to follow this step. Further, in Step 9, Second Ballot section, the 3rd paragraph states; In the second ballot step, no revisions to the standard are permitted; as such revisions would not have been subject to public comment. However, if the Standards Committee determines that revisions proposed during the ballot process would likely provide an opportunity to achieve consensus on the standard, then such revisions may be made and the draft standard posted for public comment again beginning with Step 6 and continuing with subsequent steps. NERC has revised the interpretations (contrary to the 1st sentence) and has not posted for public comment again beginning with Step 6 (contrary to the 2nd). It did not seem necessary to revise interpretations for which, from an 86.7% quorum, 88.1% voted

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		affirmative.
Response: We thank you for your comment, which addresses R1.3.2. We respectfully disagree that we have disregarded the role of the Transmission Planner. We have, however, clarified the relationship between the Planning Coordinator and the Transmission Planner. We did not proceed with a second ballot on the original interpretation because we agreed with many of the negative comments and therefore elected to revise the original interpretation instead of proceeding with a recirculation ballot. The procedure cited presumes that the comments received do not affect the standard drafting team's views on the balloted standard. In other words, it assumes that the comments do not cause the team to withdraw and revise the standard that was balloted. In our case, the comments we received in the first ballot caused us to revise our interpretation. Although the standards process does require that draft standards be posted for comment, the standards process does not require that interpretations be posted for comment. Interpretations are developed by a team and then posted for a 30-day pre-ballot review – there is no comment period for an interpretation.		
1	Omaha Public Power District	The first sentence of the revised interpretation of TPL-002 and TPL-003 R1.3.12 is actually not a complete sentence, and as a result, it is impossible to understand it. The revised interpretation therefore should not be approved in its current form. Did the Planning Committee intend to insert the words "performed is" before the word "required" in the first sentence?
Response: We agree. This appears to be a typographical error, and we will modify the first sentence by inserting the phrase "performed is" as shown: "TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are <u>performed is</u> required.		
1	Pacific Gas and Electric Company	While I agree with Interpretation 1 in that TPL standards are not meant for planning for resource adequacy. We do not necessarily disagree with Interpretation 2 because it seems to describe a planning methodology. I voted affirmative because NERC Standard is to specify what the requirements are and not how to meet them.
Response: No response is required.		
1	Sacramento Municipal Utility District	In explaining the revised interpretation for R1.3.2, that, "selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority", the interpretation dilutes the discretion given in subsequent paragraphs. Specifically, it states the "Planning Coordinator would formulate critical system conditions" and that the "the RE determines what a "valid assessment" means". The word 'formulate' is much weaker than what is stated in the requirement R1.3.2 - "as deemed appropriate" by the planning coordinator/transmission planner. The new interpretation implies that until the 'regional entity' (WECC) approves our assessment, it is not valid. I do not believe that is the requirement. The new interpretation goes beyond the stated requirement. Determining a valid assessment should stay independent of who (PA or RE) is doing it.
Response: We thank you for your comment. Our statement that the "Planning Coordinator would formulate critical system conditions" is not in conflict with our earlier statement that the "selection of critical generation dispatch for the modeling of critical system conditions is within the		

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discretion of the Planning Authority." Neither is the "would formulate" language any weaker that the "as deem appropriate" language in R.1.3.2. We have not altered this requirement. The Planning Coordinator would formulate the critical system conditions it deemed appropriate. With regards to the second comment regarding the role of the Regional Entity, in a sense an RE does "approve" a Planning Coordinator's assessment since by not issuing a compliance violation, it has determined that measures M1 and M2 are satisfied; i.e., that the assessment is valid and that it has been properly reported. (Some REs may provide affirmative approval, so that a Planning Coordinator or Transmission Planner knows that its assessment has been approved). However, an RE's obligation to determine whether an assessment is "valid" does not allow the RE to micromanage the assessments it reviews. For example, it cannot reject a corrective plan (e.g., the proposed construction of new facilities) because it believes another plan would be more cost effective. If the proposed corrective plan fulfills the standard's requirements, it is not reviewable by the RE. Finally, we did not state that an RE performed assessments as your last sentence implies.		
1	Salt River Project	R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity. Although SRP agrees that the Planning Authority (PA) shall have the discretion in choosing the appropriate conditions to study for their system(s), we disagree with the language as stated. There is no definition of how or what a PA shall do in the "methodology." Methodology is not described in any Standard to this point. Therefore, how could compliance be measured? Methodology needs to be described or enumerated to be applied in Standards and for compliance. R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed. SRP agrees with the revised interpretation of TPL-002-0 and TPL-003-0 R1.3.12 as developed by the NERC Planning Committee on March 12, 2008.
Response: We thank you for your comment. We agree that a methodology for defining "critical system conditions" is not part of TPL-002 and TPL-003. The reference to "methodology" in the interpretation comes from the Functional Model language we cited, and that citation states that the Planning Coordinator "provides…Transmission Planners …methodologies and tools for the simulation of the transmission system." We further state that a "PC's selection of "critical system conditions" falls within the purview of "methodology." We use this citation to establish the Planning Coordinator's authority for specifying "critical system conditions" which it determines are appropriate. The standards do not require a methodology, and our interpretation does not require one.		
1	Southern Indiana Gas and Electric Co.	The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008: TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL- 002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might

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		be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the NERC Glossary of Terms Used in Standards. Vectren requests that consideration be given to change the verbiage; "include any necessary system adjustments" to include the word "reasonable" or some other similar word to limit the system adjustments. The suggested verbiage would then read "include any reasonable and necessary system adjustments". Vectren does not believe that the word "necessary" provides enough limitation to the adjustments that should be considered. If the system adjustment necessary to eliminate an overload caused by the planned outage combined with contingency assessment requires an unreasonable amount of generation redispatch or the dropping of firm load, there should be some ability for the Transmission Planner or the Planning Authority to make the determination that the adjustment is unreasonable and another remedy for the overload must be explored. Your consideration in this matter is appreciated.
Response: We thank you for your comment, which addresses R1.3.12. We do not believe that the addition of the word "reasonable" has additional interpretative value. The language posed by Southern Indiana Gas and Electric Co. is an attempt to remove load shedding as a possible "necessary system adjustment" prior to modeling a contingency assessment. We do not believe that the word "reasonable" will accomplish this goal, nor do we believe it is required. It is not required because we do not believe that load shedding would ever be considered a "necessary system adjustments which might be required to accommodate planned outages" as our interpretation states. In support of this conclusion, consider TPL-002. It does not permit the loss of demand except as noted in footnote "b." If a Planning Coordinator or Transmission Planner attempted to "pass" TPL-002 by *a priori* load shedding under the guise of a "necessary system adjustment" for a planned outage, they would have shed load in order to comply with a standard that does not permit load shedding, and we would expect the RE reviewing the assessment to find it invalid.		
1	Tucson Electric Power Co.	The language in the Request for Interpretation is not clear. TEP requests clarification as to how planned outages are to be addressed. We believe planned outages, to the extent they may be known, should be treated as post-N-1 with system adjusted similar to the first event in a Category C 3 event wherein system adjustment is allowed following the outage. A distinction in the case of a planned outage may be made in that system adjustment would be implemented prior to taking the outage. In either case, system adjustment may include running generation, arming load shed for subsequent single contingencies, and/or other appropriate measures in preparation for the next event. This is important, as longer-term planned outages would include those outages needed to get system upgrades built and commissioned. Outages required to implement system upgrades should not be subjected to the same requirements as conditions with all facilities in service.
Response: We thank you for your comment, which addresses R1.3.12. Planned outages are modeled such that after the planned outage *and* any necessary system adjustments, the system is able to withstand a Category B event with Category B results. Therefore, the "necessary system adjustments" for the planned outage are taken *before* the planned outage.		

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Although a Category C 3 contemplates system adjustments *after* the first Category B event, it is not the same as a planned outage followed by a Category B event. For a Category C 3 event, the system adjustments may be "in progress" and not fully completed before the next Category B event occurs, whereas for planned outages those adjustments have been completed. Finally, a Category C 3 event permits the interruption of customers, whereas a Category B does not except as noted in footnote "b." If a planned outage were followed by a Category B event, no load loss except as noted in footnote "b" would be permitted.		
2	British Columbia Transmission Corporation	R1.3.2 The first sentence of the response is acceptable, although it could be made clearer. We suggest that the appropriate response to the question would be: R1.3.2 does not require multiple contingent generating unit outages as part of the possible generation dispatch scenarios. However, it also does not preclude this if the Planning Coordinator deems that consideration of such condition is appropriate. The last paragraph is unacceptable because it states that the Compliance Monitor determines what a "valid assessment" means. This is incorrect. The TPL standard states what a valid assessment includes. The Compliance Monitor role is to audit whether the PC's assessment includes the elements of a "valid assessment" and prescribed in the standard. R1.3.12 The statement made in the 13 March response is a correct statement. However, we do not understand the question, but do not believe the 13 March response answers the question. Since we do not understand the question, we do not know what an appropriate response would be.
Response: We thank you for your comment, which addresses R1.3.2 and R1.3.12. With regards to R1.3.2, we disagree with your statement that the Compliance Monitor does not determine whether an assessment is "valid." That is what its auditing of compliance requires. However, an RE's obligation to determine whether an assessment is "valid" does not allow the RE to micromanage the assessments it reviews. For example, it cannot reject a corrective plan (e.g., the proposed construction of new facilities) because it believes another plan would be more cost effective. If the proposed corrective plan fulfills the standard's requirements, it is not reviewable by the RE. British Columbia Transmission Corporation said it did not understand the question posed in R1.3.12. While it was in the interpretation, we have restated below: *Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.*		
2	Midwest ISO, Inc.	The Re-interpretation states in part: ** For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the NERC Glossary of

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		Terms Used in Standards. ** With regard to the revised interpretation, the Midwest ISO does not agree with the revised interpretation and at a minimum recommends the following modification in double quotation marks, for the reasons described below. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 may include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the NERC Glossary of Terms Used in Standards. ""In the alternative, if the PA or TP elected not to model in planning studies all available system adjustments and instead opted to upgrade the system to meet system performance, this would be acceptable under the requirements of the standard."" By stating that compliance would include any necessary system adjustments, this could be interpreted as non-compliance if in the discretion of the TP or PA, planning studies tested the system without applying all available system adjustments and therefore resulted in the construction of a more reliable system. It is inconceivable that NERC would judge an entity non-compliant with reliability standards for developing a more reliable system. Midwest ISO further believes strongly that the original interpretation was appropriate in articulating the discretion that TPs and PAs must have in planning their systems to be able to reasonably accommodate planned outages. Planning is performed years in advance in order that the system operator in real time will have a system that will perform reliably. All systems should be planned to be robust enough so that reasonable planned outages can be taken during typical maintenance periods (e.g. spring and fall) without the need for excessive redispatch or other operating steps merely to be able to withstand the next contingency. Large systems that include multiple separate sub-systems in close electrical proximity and with potentially redispatchable generation involving many different generation owners, must be planned to accommodate multiple planned outages on these adjoining systems. The Planning Authority over such a system must have the discretion to determine based on planning data and operating experience whether or not the interconnected system under its authority is robust enough to be able to take reasonable planned outages in several interconnected sub-systems with adequate reliability margin, and without having to resort to excessive redispatch or other operating steps in order to accommodate such planned outages. The PA may consider as excessive, for example, having to redispatch large amounts of base-load generation, or generation that does not belong to the entity taking the planned outage, or having to redispatch for a large number of separate possible planned outage conditions. The original interpretation appropriately supports this kind of discretion on the part of the PA.
Response: We thank you for your comments. The requested added language ("In the alternative, if the PA or TP elected not to model in planning studies all available system adjustments and instead opted to upgrade the system to meet system performance, this would be acceptable under the requirements of the standard.") is unacceptable for two reasons. First, our interpretation does not require “all available		

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system adjustments"; it requires only the "necessary system adjustments which might be required to accommodate the planned outages." Second, the alternative language addresses a corrective plan (i.e., upgrade the system) and not the performance of the system. It is important that a standard not comingle a corrective plan with a performance requirement. The improper modeling of system adjustments is not made acceptable by an upgrade that may not have been required if system adjustments had been properly modeled.		
3	Ameren Services Company	TPL-002-0 Requirement R.1.3.2 : Do Not Approve. The proposed interpretation of R1.3.2 does not answer the following basic question with respect to the TPL standards: Does including contingent outages as part of the defined operating state exceed the contingency requirements specified in Table 1 of the TPL standards? Defining contingent outages in the assumed system operating state is not consistent with FAC or TPL standards. FAC-010 specifies in Requirement R2.1. In the pre-contingency state with all Facilities in service TPL-002-0 Requirement R1 provides the general description for the reliability assessment of the system. R1 states that the system shall be studied under the contingency conditions as defined in Category B of Table 1. How does the interpretation address the inconsistency of modeling contingent outages as critical system conditions outside of Table 1? Could a Transmission Planner or Planning Coordinator (Authority) specify one or more contingent transmission facility outages in their critical system conditions? The contentious application of "critical system conditions" did not apply to the specification of a base case dispatch scenario. The Planning Coordinator performed a First Contingency Incremental Transfer Capability (FCITC) analysis which modeled non-firm transactions to replace contingent generation outages. Does compliance with TLP-002 require sufficient import capability to provide access to external generation capacity for which there are not explicit capacity or transmission reservations at the discretion of the Planning Coordinator? â€¢ FAC-012-1, Transfer Capability Methodology, requires that the Planning Coordinator (Authority) to document its current methodology used for developing its inter-regional and intra-regional Transfer Capabilities (Transfer Capability Methodology). Does this interpretation suggest that the Planning Coordinator has the requirement or responsibility to define a minimum level of transfer capability? Is it the intent of this interpretation that a Planning Coordinator's transfer capability methodology be applied to TPL standards compliance? â€¢ The draft interpretation states that the selection of a credible generation dispatch for modeling of critical system conditions is within the discretion of the Planning Coordinator: which of the current standards establishes a requirement that the Planning Coordinator develop a methodology to determine base case dispatch scenarios or gives the Planning Coordinator the authority to prescribe dispatch assumptions?
Response: We thank you for your comments, which address R1.3.2. However, most of the questions posed go well beyond the subject matter of the interpretation. The term "critical system conditions" is undefined in TPL-002 and TPL-003, and the standard itself gives no basis for defining it. Neither does		

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the Functional Model, a standards reference document, provide any guidance. While this is understandably what Ameren is seeking in their comments, our interpretation could not provide a direct answer. However, we were able to articulate a process for obtaining the specificity desired by Ameren, which we reiterate below. The Functional Model language cited in the interpretation supports the Planning Coordinator's supervisory role in directing the coordination of the planning process, including the specification of any methodologies to be used by Transmission Planners in its area. Such authority is also implied by a common sense reading of the standard itself. Assume that the standard was written with the understanding that the Planning Coordinator *did not* have this authority. Each of its Transmission Planners would be free to make adopt their own methods, and the Planning Coordinator's assessment as well as each Transmission Planner's assessment would be invalid on its face due solely to the lack of coordination. (Remember that M1 and M2 apply to both the Planning Coordinator *and* its Transmission Planners.) As we stated in the interpretation "As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters."		
3	BC Hydro and Power Authority	Integrated system planning roles and responsibilities in British Columbia (BC) are under review.
Response: No response is required.		
3	Consumers Energy	While the intent seems clear the following sentence from the last paragraph is not: "TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required." (What does the "are required" refer to, "inclusion" or "outages"?)
Response: We thank you for your comment. There appears to be a typographical error it the cited first sentence, and we will modify the first sentence by inserting the phrase "performed is" as shown: "TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are <u>performed is</u> required.		
3	Manitoba Hydro	Manitoba Hydro agrees with the interpretation outlined in TPL-003-0 R1.3.12; however, Manitoba Hydro does not agree with the interpretation of TPL-002-0 and TPL-003-0 R1.3.2. The standard puts the onus of defining critical system conditions on the PA/TP. The revised interpretation creates confusion as it is now unclear as to whether the PA/TP or RE as Compliance monitor is to determine the critical system conditions.
Response: We thank you for your comments. We respectfully disagree with your conclusion regarding our interpretation of R1.3.2. The Planning Coordinator has the authority to specify "critical system conditions." As we stated in the interpretation "As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters."		
3	MidAmerican Energy Co.	We believe the critcal conditions for the Transmission Planner planning should be determined

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		by the Transmission Planner while we agree that the Planning Coordinator should determine the critical conditions for the Planning Coordinator's area.
Response: We thank you for your comment, which addresses R1.3.2. However, the comment is illogical unless the Planning Coordinator and the Transmission Planner are one and the same.		
3	Orlando Utilities Commission	AMEREN: 1.3.2: Recommend Affirmative vote. AMEREN: 1.3.12: Recommend Negative Vote. Comment: The revised interpretation left out the discretion on behalf of the TP or PC. The discretion of the TP and/or PC should remain part of the interpretation since it would be impractical to perform long term studies with every possible planned outage included. The discretion part allows the TP and/or the PC to include those outages that are of significant duration and not study those that are of short duration. There are other standards and practices under which outages are reviewed so that the system is operated reliability and mandated that additional study is done under the TPL standard for even a short outage is impractical and provides no reliability gain. To address our concern we recommend replacing the first sentence; “TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required.” With the first sentence from the first interpretation: “TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed are within the discretion of the Planning Authority/Transmission Planner.” The second sentence is excellent and we agree that it addressed the question asked.
Response: We thank you for your comment. We respectfully disagree that the consideration of planned outages somehow discretionary by the Planning Coordinator or Transmission Planner. R.1.3.12 is a requirement, and as such, cannot be optional or discretionary. However, the requirement does not specify a method for the modeling of planned outages; such modeling methods are within the discretion of the Planning Authority [Planning Coordinator] to specify, and those methods should be consistently used by all its Transmission Planners.		
3	Salt River Project	R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity. Although SRP agrees that the Planning Authority (PA) shall have the discretion in choosing the appropriate conditions to study for their system(s), we disagree with the language as stated. There is no definition of how or what a PA shall do in the “methodology.” Methodology is not described in any Standard to this point. Therefore, how could compliance be measured? Methodology needs to be described or enumerated to be applied in Standards and for compliance. R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed. SRP agrees with the revised interpretation of TPL-002-0 and TPL-003-0 R1.3.12 as developed by the NERC Planning Committee on March 12, 2008.
Response: We thank you for your comment. We agree that a methodology for defining “critical system conditions” is not part of TPL-002		

Segment	Organization	Comment
and TPL-003. The reference to “methodology in the interpretation comes from the Functional Model language we cited, and that citation states that the Planning Coordinator “provides…Transmission Planners …methodologies and tools for the simulation of the transmission system.” We further state that a “PC’s selection of “critical system conditions” falls within the purview of “methodology.” We use this citation to establish the Planning Coordinator’s authority for specifying “critical system conditions” which it determines are appropriate. The standards do not require a methodology and our interpretation does not require one.		
3	Southern Indiana Gas and Electric Co.	The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008: TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL- 002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the NERC Glossary of Terms Used in Standards. Vectren requests that consideration be given to change the verbiage; "include any necessary system adjustments" to include the word "reasonable" or some other similar word to limit the system adjustments. The suggested verbiage would then read "include any reasonable and necessary system adjustments". Vectren does not believe that the word "necessary" provides enough limitation to the adjustments that should be considered. If the system adjustment necessary to eliminate an overload caused by the planned outage combined with contingency assessment requires an unreasonable amount of generation redispatch or the dropping of firm load, there should be some ability for the Transmission Planner or the Planning Authority to make the determination that the adjustment is unreasonable and another remedy for the overload must be explored. Your consideration in this matter is appreciated.
Response: We thank you for your comment, which addresses R1.3.12. We do not believe that the addition of the word “reasonable” has additional interpretative value. The language posed by Southern Indiana Gas and Electric Co. is an attempt to remove load shedding as a possible “necessary system adjustment” prior to modeling a contingency assessment. We do not believe that the word “reasonable” will accomplish this goal, nor do we believe it is required. It is not required because we do not believe that load shedding would ever be considered a “necessary system adjustment which might be required to accommodate planned outages” as our interpretation states. In support of this conclusion, consider TPL-002. It does not permit the loss of demand except as noted in footnote “b.” If a Planning Coordinator or Transmission Planner attempted to “pass” TPL-002 by *a priori* load shedding under the guise of a “necessary system adjustment” for a planned outage, they would have shed load in order to comply with a standard that does not permit load shedding, and we would expect the RE reviewing the assessment to find it invalid.		
3	Wisconsin Electric Power Marketing	We agree with the principle that the TP and TO needs to apply discretion to the contingent topology of the cases, but the actual wording in the standard does not seem to allow that discretion.

Segment	Organization	Comment
Response: We thank you for your comment. We believe that it is addressing our interpretation of R1.3.12, but are unsure. We do not state that R1.3.12 is discretionary in our revised interpretation.		
4	Wisconsin Energy Corp.	We agree with the principle that the TP and TO needs to apply discretion to the contingent topology of the cases, but the actual wording in the standard does not seem to allow that discretion.
Response: We thank you for your comment. We believe that it is addressing our interpretation of R1.3.12, but are unsure. We do not state that R1.3.12 is discretionary in our revised interpretation.		
5	City of Tallahassee	While I agree with the Revised Interpretation, I have to vote no because of the text before it that would gain teeth if this were approved. “As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner.” The Standard does NOT state “that the Compliance Monitor (or RE) has to approve the ‘valid assessment”. The Assessment is up to the PC and TP. The text quoted above IMPLIES that the RE must approve the assessment. If that is the case, put in a standard change request. The RE can only check that the assessment exists. If they don’t like it, they can make a recommendation to change it, but it is not a compliance issue. IF the text was true, I should be able to submit my assessment for evaluation without risking a compliance violation for asking for the approval that you imply is needed. The Compliance folks at the RE have told me that if we ask a question and it is a violation, we would get investigated and reported. I have to have an assessment (or procedure) and follow it, but the RE doesn’t have to like it. If they don’t like it, they can make a SUGGESTION, but not find non-compliance.
Response: We thank you for your comment. With regards to R1.3.2, we disagree with your statement that the Compliance Monitor does not determine whether an assessment is “valid.” That is what its auditing of compliance requires. However, an RE’s obligation to determine whether an assessment is “valid” does not allow the RE to micromanage the assessments it reviews. For example, it cannot reject a corrective plan (e.g., the proposed construction of new facilities) because it believes another plan would be more cost effective. If the proposed corrective plan fulfills the standard’s requirements, it is not reviewable by the RE.		
5	City Water, Light & Power of Springfield	The interpretation states that "The selection of a credible generation dispatch for the modeling under critical system conditions is within the direction of the Planning Authority." Under the proposed Version 4 of the NERC Functional Model, there is no longer a Planning Authority/Planning Coordinator. This interpretation means nothing if there is no longer a Planning Authority/Planning Coordinator.
Response: We thank you for your comment. Version 4 of the Functional Model is not approved; in fact, it was just posted for public comment, and the results have not yet been released.		
5	Dominion Energy	The original interpretation put the responsibility of determining the critical system condition on both the Planning Authority and Transmission Planner. Local Transmission Owners should

Segment	Organization	Comment
		retain the ability to have internal planning criteria for their local systems and are not precluded from doing so by the Functional Model, Version 3. This interpretation appears to preclude that and would remove the Transmission Planner as a responsible party in determining this critical system condition.
Response: We thank you for your comments. Our interpretation does not preclude a Transmission Planner from adopting stricter planning criteria than required by a standard. That is any Transmission Planner's prerogative. However, with regard to the assumptions for critical system conditions within a Planning Coordinator's area *associated with compliance with a NERC standard*, those are formulated by the Planning Coordinator.		
5	Manitoba Hydro	Manitoba Hydro agrees with the interpretation outlined in TPL-003-0 R1.3.12; however, Manitoba Hydro does not agree with the interpretation of TPL-002-0 and TPL-003-0 R1.3.2. The standard puts the onus of defining critical system conditions on the PA/TP. The revised interpretation creates confusion as it is now unclear as to whether the PA/TP or RE as Compliance monitor is to determine the critical system conditions.
Response: We thank you for your comments. We respectfully disagree with your conclusion regarding our interpretation of R1.3.2. The Planning Coordinator has the authority to specify "critical system conditions." As we stated in the interpretation "As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters."		
5	Salt River Project	R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity. Although SRP agrees that the Planning Authority (PA) shall have the discretion in choosing the appropriate conditions to study for their system(s), we disagree with the language as stated. There is no definition of how or what a PA shall do in the "methodology". Methodology is not described in any Standard to this point. Therefore, how could compliance be measured? Methodology needs to be described or enumerated to be applied in Standards and for compliance. R.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed. SRP agrees with the revised interpretation of TPL-002-0 and TPL-003-0 R1.3.12 as developed by the NERC Planning Committee on March 12, 2008.
Response: We thank you for your comment. What Salt River Project is seeking is a greater specificity in R1.3.2 and R1.3.12. However, such additional specificity cannot be provided by an interpretation.		
5	Southern California Edison Co.	Interpretation of R1.3.2 addresses the question raised by Ameren. Interpretation R1.3.12 does not fully address question posed by Ameren which led to some discussion during our internal review process.
Response: We cannot respond to this comment since no specific reason was given.		

Segment	Organization	Comment
5	Wisconsin Electric Power Co.	We agree with the principle that the TP and TO needs to apply discretion to the contingent topology of the cases, but the actual wording in the standard does not seem to allow that discretion.
Response: We thank you for your comment. We believe that it is addressing our interpretation of R1.3.12, but are unsure. We do not state that R1.3.12 is discretionary in our revised interpretation.		
6	Dominion Resources, Inc.	We do not support the removal of Transmission Planner.
Response: We cannot respond to the comment because we do not understand what part of the interpretation the comment references. In addition, it does not provide a reason.		
6	Manitoba Hydro	Manitoba Hydro agrees with the interpretation outlined in TPL-003-0 R1.3.12; however, Manitoba Hydro does not agree with the interpretation of TPL-002-0 and TPL-003-0 R1.3.2. The standard puts the onus of defining critical system conditions on the PA/TP. The revised interpretation creates confusion as it is now unclear as to whether the PA/TP or RE as Compliance monitor is to determine the critical system conditions.
Response: We thank you for your comments. We respectfully disagree with your conclusion regarding our interpretation of R1.3.2. The Planning Coordinator has the authority to specify “critical system conditions.” As we stated in the interpretation “As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters."		
6	Southern Indiana Gas and Electric Co.	The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008: TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL- 002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the NERC Glossary of Terms Used in Standards. Vectren requests that consideration be given to change the verbiage; "include any necessary system adjustments" to include the word "reasonable" or some other similar word to limit the system adjustments. The suggested verbiage would then read "include any reasonable and necessary system adjustments". Vectren does not believe that the word "necessary" provides enough limitation to the adjustments that should be considered. If the system adjustment necessary to eliminate an overload caused by the planned outage combined with contingency assessment requires an unreasonable amount of generation redispatch or the dropping of firm load, there should be some ability for the Transmission Planner or the Planning Authority to make the determination that the adjustment is unreasonable and another remedy for the overload must be explored. Your consideration in this matter is appreciated.

Segment	Organization	Comment
Response: We thank you for your comment, which addresses R1.3.12. We do not believe that the addition of the word “reasonable” has additional interpretative value. The language posed by Southern Indiana Gas and Electric Co. is an attempt to remove load shedding as a possible “necessary system adjustment” prior to modeling a contingency assessment. We do not believe that the word “reasonable” will accomplish this goal, nor do we believe it is required. It is not required because we do not believe that load shedding would ever be considered a “necessary system adjustments which might be required to accommodate planned outages” as our interpretation states. In support of this conclusion, consider TPL-002. It does not permit the loss of demand except as noted in footnote “b.” If a Planning Coordinator or Transmission Planner attempted to “pass” TPL-002 by *a priori* load shedding under the guise of a “necessary system adjustment” for a planned outage, they would have shed load in order to comply with a standard that does not permit load shedding, and we would expect the RE reviewing the assessment to reject it.		
9	Commonwealth of Massachusetts Department of Public Utilities	The interpretation says “Planning Authority/Transmission Provider”. The “and/or” can be read as either an “and” or an “or’. The difference is that the entities have to either come to a mutual agreement or can make independent assessments. Although it is thought that it will generally be a mutual decision, we think this is an issue that the two entities can work out how they address and doesn’t need to be dictated by the standard. Therefore we think the interpretation should have the “and/or” replaced with an “or”.
Response: We thank you for your comment, but it appears that your comment refers to the original interpretation of R1.3.2, not our revised interpretation.		

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standards

Ballot Results	
Ballot Name:	Request for Interpretation - TPL-002 and TPL-003 - MISO_in
Ballot Period:	4/25/2008 - 5/7/2008
Ballot Type:	Initial
Total # Votes:	171
Total Ballot Pool:	206
Quorum:	**83.01 % The Quorum has been reached**
Weighted Segment Vote:	79.89 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	64	1	35	0.714	14	0.286	4	11
2 - Segment 2.	9	0.6	5	0.5	1	0.1	1	2
3 - Segment 3.	49	1	32	0.78	9	0.22	2	6
4 - Segment 4.	8	0.7	6	0.6	1	0.1	1	0
5 - Segment 5.	35	1	19	0.731	7	0.269	3	6
6 - Segment 6.	23	1	11	0.688	5	0.313	1	6
7 - Segment 7.	1	0	0	0	0	0	0	1
8 - Segment 8.	2	0.1	1	0.1	0	0	0	1
9 - Segment 9.	7	0.5	5	0.5	0	0	0	2
10 - Segment 10.	8	0.5	5	0.5	0	0	3	0
Totals	**206**	**6.4**	**119**	**5.113**	**37**	**1.288**	**15**	**35**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services Company	Kirit S. Shah	Negative	View
1	American Transmission Company, LLC	Jason Shaver	Negative	View
1	Arizona Public Service Co.	Cary B. Deise	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Avista Corp.	Scott Kinney	Abstain	
1	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	CenterPoint Energy	Paul Rocha	Affirmative	
1	City of Tallahassee	Gary S. Brinkworth	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek		

1	Consolidated Edison Co. of New York	Edwin E. Thompson PE	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	William L. Thompson	Negative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba		
1	Entergy Corporation	George R. Bartlett	Negative	View
1	Exelon Energy	John J. Blazekovich	Abstain	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	C. Martin Mennes	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Negative	View
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	ITC Transmission	Brian F. Thumm		
1	JEA	Ted E. Hobson		
1	Kansas City Power & Light Co.	Jim Useldinger	Affirmative	
1	Keyspan LIPA	Richard J. Bolbrock		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Lower Colorado River Authority	Martyn Turner		
1	Manitoba Hydro	Michelle Rheault	Negative	View
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	Municipal Electric Authority of Georgia	Jerry J Tang	Affirmative	
1	National Grid	Michael J Ranalli	Affirmative	
1	Nebraska Public Power District	Richard L. Koch		
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Affirmative	
1	New York Power Authority	Ralph Rufrano	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Joseph Dobes	Affirmative	
1	Omaha Public Power District	Iorees Tadros	Negative	View
1	Oncor Electric Delivery	Charles W. Jenkins	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Abstain	View
1	PacifiCorp	Robert Williams		
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Sacramento Municipal Utility District	Dilip Mahendra	Negative	View
1	Salt River Project	Robert Kondziolka	Negative	View
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson		
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Christopher M. Turner	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Indiana Gas and Electric Co.	Michael Chambliss	Negative	View
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Tucson Electric Power Co.	Ronald P. Belval	Negative	View

1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Robert Temple	Affirmative	
1	Xcel Energy, Inc.	Gregory L. Pieper	Affirmative	
2	Alberta Electric System Operator	Anita Lee		
2	British Columbia Transmission Corporation	Phil Park	Negative	View
2	California ISO	David Hawkins	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Roy D. McCoy	Abstain	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	View
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
3	Alabama Power Company	Robin Hurst	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	View
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Tallahassee	Rusty S. Foster	Negative	
3	City Public Service of San Antonio	Edwin Les Barrow	Affirmative	
3	Commonwealth Edison Co.	Stephen Lesniak		
3	Consumers Energy	David A. Lapinski	Affirmative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik		
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	Entergy Services, Inc.	Matt Wolf	Negative	
3	Farmington Electric Utility System	Alan Glazner	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	
3	Florida Municipal Power Agency	Michael Alexander	Affirmative	
3	Florida Power & Light Co.	W.R. Schoneck	Abstain	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker		
3	Kissimmee Utility Authority	Gregory David Woessner		
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Ronald Dacombe	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Christopher Lawrence de Graffenried	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Negative	View
3	PECO Energy an Exelon Co.	John J. McCawley		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
	Public Utility District No. 2 of Grant			

3	County	Greg Lange	Affirmative	
3	Salt River Project	John T. Underhill	Negative	View
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern Indiana Gas and Electric Co.	Fred Frederick	Negative	View
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Cynthia Herron		
3	Wisconsin Electric Power Marketing	James R. Keller	Negative	View
3	Wisconsin Public Service Corp.	James A. Maenner	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	American Municipal Power - Ohio	Chris Norton	Abstain	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
4	WPS Resources Corp.	Christopher Plante	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tallahassee	Alan Gale	Negative	View
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Negative	View
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Affirmative	
5	Conectiv Energy Supply, Inc.	Richard K. Douglass	Affirmative	
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Energy	Harold W. Adams	Negative	View
5	Dynegy	Greg Mason	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker		
5	Entergy Corporation	Stanley M Jaskot		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	Douglas Keegan	Affirmative	
5	Florida Power & Light Co.	Robert A. Birch	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	
5	Manitoba Hydro	Mark Aikens	Negative	View
5	New York Power Authority	Richard J. Ardolino		
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	Reliant Energy Services	Thomas J. Bradish	Affirmative	
5	Salt River Project	Glen Reeves	Negative	View
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	South Carolina Electric & Gas Co.	Richard Jones		
5	Southeastern Power Administration	Douglas Spencer	Abstain	
5	Southern California Edison Co.	David Schiada	Negative	View
5	Southern Company Services, Inc.	Roger D. Green	Affirmative	
5	Southern Indiana Gas and Electric Co.	Mark Rose		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Xcel Energy, Inc.	Stephen J. Beuning	Affirmative	

6	AEP Marketing	Edward P. Cox	Affirmative	
6	AEP Service Corp.	Dana E. Horton		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Dominion Resources, Inc.	Louis S Slade	Negative	View
6	Entergy Services, Inc.	William Franklin	Negative	
6	Exelon Power Team	Pulin Shah		
6	First Energy Solutions	Alfred G. Roth		
6	Florida Municipal Power Agency	Robert C. Williams		
6	Great River Energy	Donna Stephenson		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PP&L, Inc.	Thomas Hyzinski	Affirmative	
6	Progress Energy Carolinas	James Eckelkamp	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Salt River Project	Mike Hummel	Negative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Southern Company Generation and Energy Marketing	J. Roman Carter		
6	Southern Indiana Gas and Electric Co.	Brad Lisembee	Negative	View
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Eastman Chemical Company	Lloyd Webb		
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Other	Michehl R. Gent		
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	View
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Public Service Commission	James T. Gallagher		
9	North Carolina Utilities Commission	Kimberly J. Jones	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Affirmative	
9	Wyoming Public Service Commission	Steve Oxley		
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Midwest Reliability Organization	Larry Brusseau	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Edward A. Schwerdt	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith	Affirmative	
10	SERC Reliability Corporation	Carter Edge	Abstain	
10	Southwest Power Pool	Charles H. Yeung	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Abstain	

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Standards Announcement

Initial Ballot Results for Two Interpretations
April 25–May 5, 2008

Now available at: https://standards.nerc.net/Ballots.aspx

Initial Ballot Results for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren

The initial ballot for the revised Interpretation (for Ameren) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements, was conducted from April 25–May 5, 2008.

The ballot achieved a quorum; however, there were some negative ballots with comments, initiating the need to review the comments and determine whether the interpretation needs modification before proceeding to a re-circulation ballot. The drafting team will be reviewing comments submitted with the ballot and preparing its consideration of those comments. (Detailed Ballot Results)

Quorum: 82.61 %
Approval: 80.73 %

Initial Ballot Results for Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO

The initial ballot for the revised Interpretation (for MISO) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements, was conducted from April 25–May 5, 2008.

The ballot achieved a quorum; however, there were some negative ballots with comments, initiating the need to review the comments and determine whether the interpretation needs modification before proceeding to a re-circulation ballot. The drafting team will be reviewing comments submitted with the ballot and preparing its consideration of those comments. (Detailed Ballot Results)

Quorum: 83.01 %
Approval: 79.89 %

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

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Interpretation of TPL-002-0 Requirement R1.3.2 and Requirement R1.3.12 and the Identical Requirements (R1.3.2 and R1.3.12) in TPL-003-0 for MISO

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

From TPL-002-0 and -003-0:
[To be valid, the Planning Authority and Transmission Planner assessments shall:]
R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002 and TPL-003 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions. The selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority/Transmission Planner.

The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion

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plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

From TPL-002-0 and -003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on September 12, 2007:
TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed are within the discretion of the Planning Authority/Transmission Planner.

The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:
This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interpretation of TPL-002-0 Requirement R1.3.2 and Requirement R1.3.12 and the Identical Requirements (R1.3.2 and R1.3.12) in TPL-003-0 for MISO

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

> From TPL-002-0 and -003-0:
>
> [To be valid, the Planning Authority and Transmission Planner assessments shall:]
>
> **R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002 and TPL-003 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions. The selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority/Transmission Planner.

The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former "Planning Authority" name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

– Under the Functional Model, the Planning Coordinator "Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system" while the Transmission Planner "Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion

plans." A PC's selection of "critical system conditions" and its associated generation dispatch falls within the purview of "methodology."

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2]."

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a "valid assessment" means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

From TPL-002-0 and -003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed are within the discretion of the Planning Authority/Transmission Planner.

The following revised interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards.*

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Recirculation Ballot Windows Open for Two Interpretations

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Recirculation Ballot Window for Revised Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren is Open

The recirculation ballot for the revised interpretation (for Ameren) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements, is open and will remain open until 8 p.m. (EST) on Monday, July 7, 2008.

Note that there was a typographical error in the version of the interpretation that was posted for initial ballot. The two words, "performed is" have been added to the following sentence:

> TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed is required.

The Standards Committee encourages all members of the Ballot Pool to review the consideration of comments submitted with the initial ballots. The drafting team corrected a typographical error in the last paragraph of the interpretation following the initial ballot and has posted both a clean and a redline version of the corrected interpretation. Members of the ballot pool may:

- Reconsider and change their vote from the first ballot.
- Vote in the second ballot even if they did not vote on the first ballot.
- Take no action if they do not want to change their original vote.

In the recirculation ballot, votes are counted by exception only — if a Ballot Pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot.

Recirculation Ballot Window for Revised Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO is Open

The recirculation ballot for the revised interpretation (for MISO) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements, is open and will remain open until 8 p.m. (EST) on Monday, July 7, 2008.

The Standards Committee encourages all members of the Ballot Pool to review the consideration of comments submitted with the initial ballots. The drafting team corrected a typographical error in the last paragraph of the interpretation following the initial ballot and has posted both a clean and a redline version of the corrected interpretation. Members of the ballot pool may:

- Reconsider and change their vote from the first ballot.

- Vote in the second ballot even if they did not vote on the first ballot.
- Take no action if they do not want to change their original vote.

In the recirculation ballot, votes are counted by exception only — if a Ballot Pool member does not submit a revision to that member's original vote, the vote remains the same as in the first ballot.

Standards Development Process

The *Reliability Standards Development Procedure Manual* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Maureen Long, Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

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Jeff Webb
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August 9, 2007

Maureen E. Long
Standards Process Manager
North American Electric Reliability Council
Princeton Forrestal Village
116-390 Village Boulevard
Princeton, New Jersey 0854-5721

Re: Request for Interpretation of NERC Standard TPL-002-0 and TPL-003-0

Ms. Long:

The Midwest Independent Transmission System Operator, Inc. (Midwest ISO) requests a formal interpretation of two sub requirements that are common to NERC standards TPL-002-0 and TPL-003-0, in accordance with the NERC Reliability Standards Development Procedure. The sub-requirements in question are Requirements R1.3.2 and R 1.3.12 of TPL-002 and TPL-003:

> R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
>
> R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

With respect to these two requirements, and more globally in the general application of the TPL standards, the Midwest ISO requests that NERC provide guidance with respect to the following application of the TPL standards:

1. The application of the TPL contingency requirements of Table 1 to dispatch patterns considered appropriate by the entity responsible for compliance is not a misapplication of the standard as it is within the bounds of discretion that the standard permits of the Transmission Planner and the Planning Authority as entities responsible for compliance, and;

2. The application of a standard in accordance with an existing interpretation based on the history and development of the standards is appropriate, notwithstanding future interpretations or revisions of the standard.

Specifically, with respect to the discretion that the TPL standard grants to the Transmission Planner and the Planning Authority, the Midwest ISO seeks NERC interpretation of following:

Q1.1: Do the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards?

Q1.2: If in the judgment of the entity responsible for compliance, a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch patterns?

With respect to the interpretation of R1.3.12 the Midwest ISO seeks NERC interpretation of the following:

Q2.1: Does the term "planned outages" mean only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

Q2.2: If it is intended to include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision? The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, redispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

Q2.3: If it is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard[1]?

Q2.4: If NERC provides a new interpretation of a standard, or an interpretation that is different than a prior clarification by NERC of a standard, or if NERC revises a standard, would the previous application of the standard according to the clarification, interpretation, or

[1] The NERC PSS provided responses to industry questions about the Planned Outage provision of Standard IA in September 2000, and the NERC office has these responses in their archives and has provided these to the Midwest ISO.

version of a standard in effect at the time it was applied be considered a proper application of the standard? Is the more recent interpretation deemed to be retroactive, invalidating previous planning studies?

Material Impact of Standards Interpretation

- Necessary transmission expansions may not be pursued depending on the interpretation of these issues. Regulatory authorities may not permit recovery of costs of appropriately planned transmission expansions if the NERC standards are construed to prescribe the precise system conditions that are appropriate to be planned for without permitting discretion in planning assumptions to be within the proper application of the NERC standards.

- The application of the NERC standards must permit that discretion be given to Transmission Planners and Planning Authorities to apply appropriate planning assumptions for their systems in development of planning models that the NERC standards are applied to. If the NERC standards are interpreted as specifically prescribing the generation patterns, including the number of generators off-line that it is prudent to plan for, it will make it difficult for Transmission Planners and Planning Authorities to plan their specific systems to perform reliably based on their experience with and the historical performance of their systems.

- If the interpretation, reinterpretation, or revision of a standard subsequent to the application of a standard to support the need for reliability upgrades renders the prior application of a standard inappropriate in NERC's view, this would create great uncertainty in the ability of a Transmission owner to recover costs for upgrades, and would result in reluctance by Transmission Owners to expand their systems based on present interpretations of the standards.

The Midwest ISO appreciates the prompt attention of NERC to the issues outlined in this request, and requests that we be kept informed of actions taken by NERC pursuant to this request.

Sincerely,

Jeffrey R. Webb
Director of Expansion Planning
Midwest ISO

Reliability Standards

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Ballot Results	
Ballot Name:	Request for Interpretation - TPL-002 and TPL-003 - MISO_rc
Ballot Period:	6/27/2008 - 7/7/2008
Ballot Type:	recirculation
Total # Votes:	173
Total Ballot Pool:	206
Quorum:	**83.98 % The Quorum has been reached**
Weighted Segment Vote:	78.31 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	64	1	37	0.74	13	0.26	4	10
2 - Segment 2.	9	0.6	5	0.5	1	0.1	1	2
3 - Segment 3.	49	1	32	0.78	9	0.22	2	6
4 - Segment 4.	8	0.7	5	0.5	2	0.2	1	0
5 - Segment 5.	35	1	19	0.704	8	0.296	3	5
6 - Segment 6.	23	1	11	0.688	5	0.313	1	6
7 - Segment 7.	1	0	0	0	0	0	0	1
8 - Segment 8.	2	0.1	1	0.1	0	0	0	1
9 - Segment 9.	7	0.5	5	0.5	0	0	0	2
10 - Segment 10.	8	0.5	5	0.5	0	0	3	0
Totals	**206**	**6.4**	**120**	**5.012**	**38**	**1.389**	**15**	**33**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services Company	Kirit S. Shah	Negative	View
1	American Transmission Company, LLC	Jason Shaver	Negative	View
1	Arizona Public Service Co.	Cary B. Deise	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Avista Corp.	Scott Kinney	Abstain	
1	Basin Electric Power Cooperative	David Rudolph	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	CenterPoint Energy	Paul Rocha	Affirmative	
1	City of Tallahassee	Gary S. Brinkworth	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek		
1	Consolidated Edison Co. of New York	Edwin E. Thompson PE	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	

1	Dominion Virginia Power	William L. Thompson	Negative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba		
1	Entergy Corporation	George R. Bartlett	Negative	View
1	Exelon Energy	John J. Blazekovich	Abstain	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	C. Martin Mennes	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Negative	View
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Damon Holladay	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	ITC Transmission	Brian F. Thumm		
1	JEA	Ted E. Hobson		
1	Kansas City Power & Light Co.	Jim Useldinger	Affirmative	
1	Keyspan LIPA	Richard J. Bolbrock		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Lower Colorado River Authority	Martyn Turner		
1	Manitoba Hydro	Michelle Rheault	Negative	View
1	Minnesota Power, Inc.	Carol Gerou	Affirmative	
1	Municipal Electric Authority of Georgia	Jerry J Tang	Affirmative	
1	National Grid	Michael J Ranalli	Affirmative	
1	Nebraska Public Power District	Richard L. Koch		
1	New Brunswick Power Transmission Corporation	Wayne N. Snowdon	Affirmative	
1	New York Power Authority	Ralph Rufrano	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Joseph Dobes	Affirmative	
1	Omaha Public Power District	lorees Tadros	Affirmative	
1	Oncor Electric Delivery	Charles W. Jenkins	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Abstain	View
1	PacifiCorp	Robert Williams	Affirmative	
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PP&L, Inc.	Ray Mammarella	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Sacramento Municipal Utility District	Dilip Mahendra	Negative	View
1	Salt River Project	Robert Kondziolka	Negative	View
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SaskPower	Wayne Guttormson		
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Christopher M. Turner	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Indiana Gas and Electric Co.	Michael Chambliss	Negative	View
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Tucson Electric Power Co.	Ronald P. Belval	Negative	View
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Robert Temple	Affirmative	
1	Xcel Energy, Inc.	Gregory L. Pieper	Affirmative	
2	Alberta Electric System Operator	Anita Lee		
2	British Columbia Transmission Corporation	Phil Park	Negative	View
2	California ISO	David Hawkins	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Roy D. McCoy	Abstain	

2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Terry Bilke	Affirmative	View
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
3	Alabama Power Company	Robin Hurst	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	View
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Tallahassee	Rusty S. Foster	Negative	
3	City Public Service of San Antonio	Edwin Les Barrow	Affirmative	
3	Commonwealth Edison Co.	Stephen Lesniak		
3	Consumers Energy	David A. Lapinski	Affirmative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik		
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	Entergy Services, Inc.	Matt Wolf	Negative	
3	Farmington Electric Utility System	Alan Glazner	Affirmative	
3	FirstEnergy Solutions	Joanne Kathleen Borrell	Affirmative	
3	Florida Municipal Power Agency	Michael Alexander	Affirmative	
3	Florida Power & Light Co.	W.R. Schoneck	Abstain	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Leslie Sibert	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker		
3	Kissimmee Utility Authority	Gregory David Woessner		
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Ronald Dacombe	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Christopher Lawrence de Graffenried	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Negative	View
3	PECO Energy an Exelon Co.	John J. McCawley		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Salt River Project	John T. Underhill	Negative	View
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern Indiana Gas and Electric Co.	Fred Frederick	Negative	View
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Cynthia Herron		
3	Wisconsin Electric Power Marketing	James R. Keller	Negative	View
3	Wisconsin Public Service Corp.	James A. Maenner	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	American Municipal Power - Ohio	Chris Norton	Abstain	
4	Consumers Energy	David Frank Ronk	Affirmative	

4	Northern California Power Agency	Fred E. Young	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R. Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
4	WPS Resources Corp.	Christopher Plante	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	City of Tallahassee	Alan Gale	Negative	View
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Negative	View
5	Colmac Clarion/Piney Creek LP	Harvie D. Beavers	Affirmative	
5	Conectiv Energy Supply, Inc.	Richard K. Douglass	Affirmative	
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Energy	Harold W. Adams	Negative	View
5	Dynegy	Greg Mason	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker		
5	Entergy Corporation	Stanley M Jaskot	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	Douglas Keegan	Affirmative	
5	Florida Power & Light Co.	Robert A. Birch	Affirmative	
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	
5	Manitoba Hydro	Mark Aikens	Negative	View
5	New York Power Authority	Richard J. Ardolino		
5	PPL Generation LLC	Mark A. Heimbach	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	Reliant Energy Services	Thomas J. Bradish	Affirmative	
5	Salt River Project	Glen Reeves	Negative	View
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	South Carolina Electric & Gas Co.	Richard Jones		
5	Southeastern Power Administration	Douglas Spencer	Abstain	
5	Southern California Edison Co.	David Schiada	Negative	View
5	Southern Company Services, Inc.	Roger D. Green	Affirmative	
5	Southern Indiana Gas and Electric Co.	Mark Rose		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Xcel Energy, Inc.	Stephen J. Beuning	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	AEP Service Corp.	Dana E. Horton		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	Dominion Resources, Inc.	Louis S Slade	Negative	View
6	Entergy Services, Inc.	William Franklin	Negative	
6	Exelon Power Team	Pulin Shah		
6	First Energy Solutions	Alfred G. Roth		
6	Florida Municipal Power Agency	Robert C. Williams		
6	Great River Energy	Donna Stephenson		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	New York Power Authority	Thomas Papadopoulos	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PP&L, Inc.	Thomas Hyzinski	Affirmative	
6	Progress Energy Carolinas	James Eckelkamp	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	

6	Salt River Project	Mike Hummel	Negative	
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Southern Company Generation and Energy Marketing	J. Roman Carter		
6	Southern Indiana Gas and Electric Co.	Brad Lisembee	Negative	View
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
7	Eastman Chemical Company	Lloyd Webb		
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Other	Michehl R. Gent		
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	View
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	New York State Public Service Commission	James T. Gallagher		
9	North Carolina Utilities Commission	Kimberly J. Jones	Affirmative	
9	Public Utilities Commission of Ohio	Klaus Lambeck	Affirmative	
9	Wyoming Public Service Commission	Steve Oxley		
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Affirmative	
10	Midwest Reliability Organization	Larry Brusseau	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Edward A. Schwerdt	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Abstain	
10	Southwest Power Pool	Charles H. Yeung	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Abstain	

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Standards Announcement

Final Ballot Results for Two Interpretations (Project 2007-24 and Project 2007-26)

Now available at: https://standards.nerc.net/Ballots.aspx

Final Ballot Results for Project 2007-24 — Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren

The recirculation ballot for the revised Interpretation (for Ameren) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements was conducted from June 27–July 7, 2008 and the ballot was approved.

The Ballot Results standards Web page provides a link to the detailed results for this ballot.

Quorum:	83.57 %
Approval:	79.13 %

Approval requires both:

- A quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention; and
- A two-thirds majority of the weighted segment votes cast must be affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding abstentions and no responses.

Final Ballot Results for Project 2007-26 — Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for MISO

The recirculation ballot for the revised Interpretation (for MISO) of Requirements R1.3.2 and R1.3.12 in both TPL-002-0 — System Performance Following the Loss of a Single Bulk Electric System Element and TPL-003-0 — System Performance Following Loss of Two or More Bulk Electric System Elements, was conducted from June 27–July 7, 2008 and the ballot was approved.

The Ballot Results standards Web page provides a link to the detailed results for this ballot.

Quorum:	83.98 %
Approval:	78.31 %

Approval requires both:

- A quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention; and
- A two-thirds majority of the weighted segment votes cast must be affirmative. The number of votes cast is the sum of affirmative and negative votes, excluding abstentions and no responses.

Standards Development Process

The *Reliability Standards Development Procedure Manual* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Maureen Long,
Standards Process Manager, at maureen.long@nerc.net or at (813) 468-5998.

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